Canadian Utilities Limited
2010 Financial Information

For The Year Ended
December 31, 2010

CANADIAN UTILITIES LIMITED
An ATCO Company

2010 Financial Information

CONSOLIDATED FINANCIAL STATEMENTS

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

FOR THE YEAR ENDED DECEMBER 31, 2010

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MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL REPORTING

Management is responsible for the preparation of the consolidated financial statements, management's discussion and analysis of financial condition and results of operations and other financial information relating to the Corporation contained in this annual report. The consolidated financial statements have been prepared in conformity with Canadian generally accepted accounting principles using methods appropriate for the industries in which the Corporation operates and necessarily include some amounts that are based on informed judgments and best estimates of management. The financial information contained elsewhere in the annual report is consistent with that in the consolidated financial statements.

PricewaterhouseCoopers, our independent auditors, are engaged to express a professional opinion on the consolidated financial statements.

Management has established internal accounting and financial reporting control systems, which are subject to periodic review by the Corporation's internal auditors, to meet its responsibility for reliable and accurate reporting. Integral to these control systems are a code of ethics and management policies that provide guidance and direction to employees, as well as a system of corporate governance that provides oversight to the Corporation's operating, reporting and risk management activities.

The Board of Directors, through its Audit Committee comprised entirely of outside Directors, oversees management's responsibilities for financial reporting. The Audit Committee meets regularly with management, the internal auditors and the independent auditors to discuss auditing and reporting on financial matters, to assure that management is carrying out its responsibilities and to review and approve the consolidated financial statements. The auditors have full and free access to the Audit Committee and management.

N.C. South | B.R. Bale

N.C. Southern
Deputy Chair, President & Chief Executive Officer

B.R. Bale
Senior Vice President & Chief Financial Officer

INDEPENDENT AUDITOR'S REPORT

TO THE SHARE OWNERS OF CANADIAN UTILITIES LIMITED

We have audited the accompanying consolidated financial statements of Canadian Utilities Limited, which comprise the consolidated balance sheets as at December 31, 2010 and December 31, 2009 and the consolidated statements of earnings and retained earnings, cash flows and comprehensive income for the years then ended, and the related notes including a summary of significant accounting policies.

Management's responsibility for the consolidated financial statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statement that are free from material misstatement, whether due to fraud or error.

Auditor's responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation

and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Canadian Utilities Limited as at December 31, 2010 and December 31, 2009 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP

Chartered Accountants
Calgary, Alberta
February 22, 2011

Canadian Utilities Limited
Consolidated Statement of Earnings and Retained Earnings
(Millions of Canadian Dollars except per share data)

	Note	Three Months Ended December 31 2010	2009	Year Ended December 31 2010	2009
		(Unaudited)			
Revenues		$ 709.3	$ 675.6	$2,657.2	$2,584.0
Costs and expenses					
Natural gas supply		51.4	4.3	88.7	23.2
Purchased power		14.7	14.3	54.2	54.1
Operation and maintenance		218.2	233.5	974.8	965.5
Selling and administrative		80.6	80.2	266.7	258.7
Depreciation and amortization		82.4	80.4	335.5	329.7
Interest	12	55.7	60.7	235.9	241.6
Franchise fees		46.8	43.9	172.7	163.5
		549.8	517.3	2,128.5	2,036.3
		159.5	158.3	528.7	547.7
Gain on ATCO Structures & Logistics transaction	4	-	-	-	33.9
Earnings from investment in ATCO Structures & Logistics	4	4.9	4.1	19.7	7.8
Interest and other income	5	8.2	9.6	39.3	43.3
Earnings before income taxes		172.6	172.0	587.7	632.7
Income taxes	6	32.9	34.1	109.2	125.4
		139.7	137.9	478.5	507.3
Dividends on equity preferred shares		11.1	10.8	43.5	40.7
Earnings attributable to Class A and Class B shares		128.6	127.1	435.0	466.6
Retained earnings at beginning of period		2,728.0	2,485.8	2,568.6	2,279.1
		2,856.6	2,612.9	3,003.6	2,745.7
Dividends on Class A and Class B shares		47.5	44.3	190.0	177.1
Purchase of Class A shares		1.4	-	5.9	-
Retained earnings at end of period		$2,807.7	$2,568.6	$2,807.7	$2,568.6
Earnings per Class A and Class B share	15	$ 1.02	$ 1.01	$ 3.46	$ 3.71
Diluted earnings per Class A and Class B share	15	$ 1.02	$ 1.01	$ 3.45	$ 3.71
Dividends paid per Class A and Class B share	15	$ 0.3775	$ 0.3525	$ 1.51	$ 1.41

Canadian Utilities Limited
Consolidated Balance Sheet

(Millions of Canadian Dollars)

	Note	December 31 2010	2009
ASSETS			
Current assets			
Cash and short term investments	19	**$ 539.6**	$ 796.0
Accounts receivable		**407.9**	366.4
Inventories	7	**82.0**	79.8
Income taxes recoverable	6	**-**	8.5
Future income taxes	6	**2.0**	6.6
Regulatory assets	2	**16.9**	37.4
Derivative assets	22	**2.9**	1.2
Prepaid expenses and other assets		**30.7**	32.0
		1,082.0	1,327.9
Property, plant and equipment	8	**7,036.3**	6,732.7
Intangibles	9	**259.1**	241.8
Investment in ATCO Structures & Logistics	4	**137.9**	121.9
Regulatory assets	2	**460.7**	383.9
Derivative assets	22	**5.8**	31.4
Other assets	10	**433.5**	244.0
		$9,415.3	$9,083.6
LIABILITIES AND SHARE OWNERS' EQUITY			
Current liabilities			
Accounts payable and accrued liabilities		**$ 404.9**	$ 382.1
Income taxes payable		**0.6**	-
Regulatory liabilities	2	**17.0**	26.1
Derivative liabilities	22	**2.9**	2.9
Long term debt due within one year	12	**3.3**	2.8
Non-recourse long term debt due within one year	12	**38.3**	49.0
		467.0	462.9
Future income taxes	6	**540.7**	478.1
Regulatory liabilities	2	**666.1**	571.2
Derivative liabilities	22	**6.1**	5.9
Deferred credits	13	**237.1**	277.3
Long term debt	12	**3,060.3**	3,102.3
Non-recourse long term debt	12	**302.8**	354.8
Equity preferred shares	14	**860.0**	785.0
Class A and Class B share owners' equity			
Class A and Class B shares	15	**533.1**	528.3
Contributed surplus	17	**1.2**	3.2
Retained earnings		**2,807.7**	2,568.6
Accumulated other comprehensive income	23	**(66.8)**	(54.0)
Retained earnings and accumulated other comprehensive income		**2,740.9**	2,514.6
		3,275.2	3,046.1
		$9,415.3	$9,083.6

N.C. Southern

DIRECTOR

DIRECTOR

Canadian Utilities Limited
Consolidated Statement of Cash Flows

(Millions of Canadian Dollars)

	Note	Three Months Ended December 31 2010	Three Months Ended December 31 2009	Year Ended December 31 2010	Year Ended December 31 2009
		(Unaudited)			
Operating activities					
Earnings attributable to Class A and Class B shares		**$ 128.6**	$ 127.1	**$ 435.0**	$ 466.6
Adjustments for:					
Depreciation and amortization		**82.4**	80.4	**335.5**	329.7
Future income taxes		**(11.6)**	(5.3)	**(7.4)**	0.8
Gain on ATCO Structures & Logistics transaction	4	**-**	-	**-**	(33.9)
Earnings from investment in ATCO Structures & Logistics		**(4.9)**	(4.1)	**(19.7)**	(7.8)
Dividends received from ATCO Structures & Logistics	4	**2.5**	5.1	**4.9**	5.9
TXU Europe settlement - net of income taxes		**-**	(2.1)	**(6.0)**	(8.9)
Mark to market of natural gas purchase and power generation revenue contracts	5	**2.2**	2.7	**7.8**	9.9
Deferred availability incentives		**3.3**	3.7	**(18.9)**	5.9
Changes in non-current regulatory assets and liabilities		**(7.0)**	31.4	**30.9**	41.6
Allowance for equity funds used during construction		**(2.8)**	(3.5)	**(7.8)**	(9.0)
Other		**(6.5)**	(6.3)	**(16.1)**	(7.4)
		186.2	229.1	**738.2**	793.4
Changes in non-cash working capital	18	**4.2**	(65.9)	**26.1**	(55.1)
Cash flow from operations		**190.4**	163.2	**764.3**	738.3
Investing activities					
Purchase of property, plant and equipment		**(249.7)**	(243.8)	**(822.1)**	(887.5)
Proceeds on disposal of property, plant and equipment		**0.8**	-	**16.3**	0.2
Contributions by utility customers for extensions to plant		**17.7**	20.7	**66.0**	114.1
Purchase of intangibles		**(20.7)**	(29.9)	**(46.9)**	(58.6)
Changes in non-cash working capital	18	**12.9**	52.8	**(3.1)**	(29.5)
Other		**3.0**	4.0	**12.3**	9.2
		(236.0)	(196.2)	**(777.5)**	(852.1)
Financing activities					
Issue of long term debt	12	**125.0**	23.7	**125.0**	399.7
Repayment of long term debt	12	**(2.3)**	(125.3)	**(175.1)**	(134.1)
Repayment of non-recourse long term debt	12	**(14.9)**	(12.2)	**(61.7)**	(55.8)
Issue of equity preferred shares by subsidiary	14	**75.0**	-	**75.0**	160.0
Net issue (purchase) of Class A shares		**1.9**	3.7	**(1.1)**	6.4
Dividends paid to Class A and Class B share owners		**(47.5)**	(44.3)	**(190.0)**	(177.1)
Other		**(3.2)**	1.0	**(4.4)**	(2.1)
		134.0	(153.4)	**(232.3)**	197.0
Foreign currency translation		**(5.6)**	(1.4)	**(10.9)**	(4.9)
Cash position [(1)]					
Increase (decrease)		**82.8**	(187.8)	**(256.4)**	78.3
Decrease in cash on ATCO Structures & Logistics transaction	4	**-**	-	**-**	(8.9)
Beginning of period		**456.8**	983.8	**796.0**	726.6
End of period		**$ 539.6**	$ 796.0	**$ 539.6**	$ 796.0

Canadian Utilities Limited
Consolidated Statement of Comprehensive Income
(Millions of Canadian Dollars)

		Three Months Ended December 31		Year Ended December 31	
	Note	**2010**	2009	**2010**	2009
		(Unaudited)			
Earnings attributable to Class A and Class B shares		**$128.6**	$127.1	**$435.0**	$466.6
Other comprehensive income, net of income taxes:					
Cash flow hedges	23	**2.5**	1.3	**1.4**	8.3
Foreign currency translation adjustment	23	**(9.2)**	(3.1)	**(14.2)**	(6.1)
		(6.7)	(1.8)	**(12.8)**	2.2
Comprehensive income		**$121.9**	$125.3	**$422.2**	$468.8

Canadian Utilities Limited
Notes to Consolidated Financial Statements
December 31, 2010
(tabular amounts in millions of Canadian dollars)

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Financial Statement Presentation and Consolidation

The accompanying consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). The consolidated financial statements include the accounts of Canadian Utilities Limited and its subsidiaries, including a proportionate share of joint venture investments and an equity accounted for investment in ATCO Structures & Logistics (the "Corporation"). Significant investments and principal subsidiaries are listed below. Subsidiaries are wholly-owned, unless otherwise indicated.

Significant Investments and Principal Operating Subsidiaries	Principal Activity
ATCO Structures & Logistics [1]	Infrastructure solutions including support services & logistics, modular building solutions and supply, and construction of noise management solutions
ATCO Power	Power generation
Alberta Power (2000) [2]	Power generation
ATCO Midstream	Natural gas gathering, processing, storage and natural gas liquids extraction
ATCO I-Tek	Information systems and technologies
CU Inc.	Holding company
ATCO Gas [3]	Natural gas distribution
ATCO Pipelines [3]	Natural gas transmission
ATCO Electric [3]	Electric transmission and distribution

[1] At December 31, 2010, the Corporation has an ownership interest of 24.5% and ATCO Ltd., the Corporation's parent, has an ownership interest of 75.5%. The Corporation accounts for its investment in ATCO Structures & Logistics under the equity method.

[2] Effective October 1, 2010, the 100% ownership interest in Alberta Power (2000) Ltd. was transferred from CU Inc. to ATCO Power Ltd. This transfer had no impact on the financial position, results of operations and cash flows of the Corporation.

[3] Wholly owned by CU Inc.

Significant joint ventures consist principally of power generation plants; a substantial portion of ATCO Power's operations are conducted through joint ventures.

Rate Regulation

ATCO Electric and its subsidiaries, Northland Utilities (NWT), Northland Utilities (Yellowknife) and Yukon Electrical, the ATCO Gas and ATCO Pipelines divisions of ATCO Gas and Pipelines Ltd. and the Battle River and Sheerness generating plants of Alberta Power (2000) are collectively referred to in these consolidated financial statements as the "regulated operations". Accounting for rate regulated operations is described in Note 2. The Corporation records revenues and/or other adjustments arising from an interim or final rate decision related to current and/or prior years upon receipt of the decision.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Significant Judgments and Estimates

The preparation of the Corporation's consolidated financial statements in accordance with GAAP requires management to make judgments, estimates and assumptions that affect the application of policies and reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the year. On an on-going basis, management reviews its estimates, particularly those related to revenue recognition, regulatory assets and liabilities, depreciation and amortization methods, useful lives and impairment of long-lived assets, amortization of deferred availability incentives, asset retirement obligations, pensions and other post-employment benefits and the fair value of financial instruments, using currently available information. Changes in facts and circumstances may result in revised estimates, and actual results could differ from those estimates. Revisions to accounting estimates are recognized in the period in which the estimate is revised if the revision affects only that period, or in the period of the revision and future periods if the revision affects both current and future periods.

Revenue Recognition

For regulated operations, revenues are recognized in a manner that is consistent with the underlying rate design as mandated by the regulator.

Revenues from ATCO Gas' regulated distribution of natural gas and ATCO Electric's regulated distribution of electricity include variable charges, which are recognized on the basis of meter readings upon delivery of the respective commodity to customers and include an estimate of usage not yet billed, and fixed charges, based on the provision of the distribution service during the period.

Revenues for the use of ATCO Electric's regulated transmission facilities are based on an annual tariff and are recognized evenly throughout the year.

Revenues from ATCO Pipelines' regulated transmission of natural gas are recognized on the basis of contractual arrangements. For certain services, revenues are recognized on the basis of meter readings upon delivery of natural gas to customers and include an estimate of usage not yet billed.

Revenues from regulated sales and distribution of natural gas and electricity by other regulated operations, excluding Alberta Power (2000), are recognized upon delivery, primarily on the basis of meter readings, and include an estimate of usage not yet billed.

Measurement of the estimate of usage not yet billed is based on historical consumption patterns. Management applies judgment to the measurement of the estimated consumption and to the valuation of that consumption.

Incentives and penalties associated with Alberta Power (2000)'s Power Purchase Arrangements ("PPA") are recognized as described under the accounting policy for deferred availability incentives.

Revenues from generating plants are recognized upon delivery of output or upon availability of delivery as prescribed by contractual arrangements.

Revenues from ATCO Midstream's natural gas storage and processing capacity are recognized on the basis of contractual arrangements, and revenues from the sale of natural gas liquids are recognized upon delivery.

Revenues resulting from the supply of contracted products and services are recorded by the percentage of completion method; full provision is made for any anticipated loss. Other revenues are recognized when products are delivered or services are provided. Billings in excess of earned revenue are deferred as unearned revenue.

Natural Gas Supply

Natural gas supply expense for ATCO Midstream, which consists of natural gas volumes purchased for natural gas liquids extraction and sales to third parties, is based on actual costs incurred.

Purchased Power

Purchased power expense for regulated operations of ATCO Electric in the Yukon Territory and the Northwest Territories is based on the actual cost of electricity purchased. The amount included in customer rates in the Yukon Territory is based on actual costs and in the Northwest Territories is based on forecast cost. Revenues are adjusted for variances from forecast cost, and the variances are deferred until such time as approval from the regulator is obtained for refund to or collection from customers.

Franchise Fees

Franchise fees are charged to ATCO Electric, ATCO Gas and ATCO Pipelines (the "Utilities") by municipal governments for the exclusive right to provide service in their community. These costs are charged to the related customers through rates that must first be approved by the Alberta Utilities Commission ("AUC"). Franchise fee revenues and expenses are therefore recognized separately and are not recorded on a net basis.

Income Taxes

The Corporation follows the liability method of accounting for income taxes. Under this method, future tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases. Future tax liabilities and assets are measured using enacted and substantively enacted tax rates. For the Utilities a separate regulatory asset or liability is recognized for the amount of future income taxes expected to be included in future rates and recovered from or paid to future customers.

Cash and Short Term Investments

Short term investments consist of bankers' acceptances, certificates of deposit issued or guaranteed by credit worthy financial institutions and federal government issued short term investments with maturities generally of 90 days or less at purchase.

Inventories

Inventories are valued at the lower of cost or net realizable value. The cost of inventories is assigned using the weighted average cost method. Net realizable value is the estimated selling price in the ordinary course of business, less applicable variable selling expenses.

The cost of inventories is comprised of all costs of purchase, costs of conversion and other costs to bring the inventories to their present condition and location. The costs of purchase comprise the purchase price, import duties and non-recoverable taxes, and transport, handling and other costs directly attributable to

the acquisition of finished goods, materials or services. The costs of conversion include direct material and labour costs and a systematic allocation of fixed and variable overheads incurred in converting materials into finished goods.

Property, Plant and Equipment

Property, plant and equipment are recorded at cost less accumulated depreciation and unamortized contributions by utility customers for extensions to plant.

Regulated operations include in property, plant and equipment an allowance for funds used during construction at rates approved by the AUC for debt and equity capital. Property, plant and equipment in the non-regulated subsidiaries include capitalized interest incurred during construction.

Certain regulated additions are made with the assistance of non-refundable cash contributions from customers when the estimated revenue is less than the cost of providing service or where special equipment is needed to supply the customers' specific requirements. These contributions are amortized on the same basis as, and offset the depreciation charge of, the assets to which they relate.

Depreciation is provided on assets on a straight-line basis over their estimated useful lives. Depreciation rates for regulated assets, excluding Alberta Power (2000)'s generating plants, are approved by the AUC. On retirement of these depreciable regulated assets, the accumulated depreciation is charged with the cost of the retired unit, net disposal costs and site restoration costs.

Intangibles

Intangibles mainly include computer software not directly attributable to the operation of property, plant and equipment and land rights and are recorded at cost less accumulated amortization and unamortized contributions by utility customers. The assets are amortized on a straight-line basis over their useful lives, which are not longer than 10 years for computer software and between 75 and 100 years for land rights.

Impairment

Property, plant and equipment and intangible assets with finite lives are tested for recoverability whenever events or changes in circumstances indicate a possible impairment. An impairment of property, plant and equipment and intangible assets with finite lives is recognized in earnings when the asset's carrying value exceeds the total cash flows expected from its use and eventual disposition. The impairment loss is then calculated as the difference between the asset's carrying value and its fair value, which is determined using discounted future cash flows.

Deferred Financing Charges

Issue costs of long term debt are amortized over the life of the debt using the effective interest method. Issue costs of preferred shares relating to regulated operations are amortized over the expected life of the issue in accordance with accounting for rate regulated operations and issue costs of preferred shares relating to non-regulated subsidiaries are charged to retained earnings. Unamortized premiums and issue costs of redeemed long term debt and preferred shares relating to regulated operations are amortized over the life of the issue funding the redemption. The Corporation's presentation of long term debt and non-recourse long term debt are reduced by the respective deferred financing charges.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Leases

The Corporation is party to certain arrangements that convey the right to use non-regulated electric transmission assets and are classified as leases with the Corporation as the lessor. Leases are classified as finance leases when the terms of the lease transfer substantially all the risks and rewards incidental to ownership of the leased asset to the lessee. Amounts due from lessees under finance leases are recorded as receivables included within other assets. Finance lease receivables are initially recognized at amounts equal to the present value of the minimum lease payments receivable. Finance lease income is recognized in a manner that produces a constant rate of return on the Corporation's investment in the lease and is included in interest and other income.

Deferred Availability Incentives

Under the terms of the PPAs, the Corporation is subject to an incentive/penalty regime related to generating unit availability. Incentives are paid to the Corporation by the PPA counterparties for availability in excess of predetermined targets, whereas penalties are paid by the Corporation to the PPA counterparties when the availability targets are not achieved.

Accumulated incentives in excess of accumulated penalties are deferred. For any of the individual PPAs, should accumulated incentives plus estimated future incentives exceed accumulated penalties plus estimated future penalties, the excess will be amortized to revenues on a straight-line basis over the remaining term of the PPAs. Should accumulated penalties plus estimated future penalties exceed accumulated incentives plus estimated future incentives, the shortfall will be expensed in the year the shortfall occurs.

Asset Retirement Obligations

Asset retirement obligations are legal obligations associated with the retirement of tangible long lived assets. These obligations are measured and recognized at fair value, which is determined using discounted future cash flows.

An asset retirement obligation is recorded as a liability in deferred credits, with a corresponding increase to property, plant and equipment. The liability is accreted over the estimated time period until settlement of the obligation, with the accretion expense included in depreciation and amortization. The asset is depreciated over its estimated useful life.

Asset retirement obligations have been recorded for the regulated and non-regulated electricity generating plants and the natural gas liquids extraction and processing plants.

Long Term Debt Due Within One Year

When the Corporation intends to refinance long term debt due within one year on a long term basis and there is a written undertaking from an underwriter to act on the Corporation's behalf with respect thereto, or sufficient capacity exists under long term bank loan agreements to issue commercial paper or assume bank loans, then long term debt due within one year is classified as long term.

Financial Instruments

The Corporation establishes the classification of financial instruments at their initial recognition. Financial assets are classified as held for trading, available for sale, held to maturity or loans and receivables. Financial liabilities are classified as held for trading or other liabilities.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Financial instruments classified as held for trading, other than derivative instruments that are effective hedging instruments, are measured at fair value with changes in fair value recognized in earnings. Derivatives that are designated as, and continue to be, highly effective cash flow hedging instruments have gains and losses in fair values recognized through other comprehensive income. Derivatives that are designated as fair value hedging instruments have gains and losses recognized in earnings.

Financial instruments classified as available for sale are measured at fair value using quoted prices in an active market. Changes in fair value are recognized in other comprehensive income until the item is derecognized or determined to be impaired, at which time the cumulative gain or loss previously reported in other comprehensive income is recognized in earnings. When actively quoted prices are not available, fair value is determined using other valuation techniques. If fair value cannot be reliably estimated, the item is carried at cost.

Financial instruments classified as held to maturity, loans and receivables or other liabilities are measured at fair value upon initial recognition but are subsequently measured at their amortized cost using the effective interest method.

In estimating fair value, the Corporation utilizes quoted market prices when available. Models incorporating observable market data along with transaction specific factors are also utilized in estimating fair value. Financial assets and liabilities are classified in the fair value hierarchy according to the lowest level of input that is significant to the fair value measurement. Assessment of the significance of a particular input to the fair value measurement requires judgment and may affect placement within the fair value hierarchy levels. The hierarchy is as follows:

- Level 1: quoted prices (unadjusted) in active markets for identical assets or liabilities.
- Level 2: inputs other than quoted prices included in Level 1 that are observable for the asset or liability, either directly (i.e., as prices) or indirectly (i.e., derived from prices).
- Level 3: inputs for the asset or liability that are not based on observable market data (unobservable inputs)

The Corporation applies settlement date accounting to the purchases and sales of financial assets. Settlement date accounting implies the recognition of an asset on the day it is received by the Corporation and the recognition of the disposal of an asset on the day that it is delivered by the Corporation. Any gain or loss on disposal is also recognized on that day.

Transaction costs that are directly attributable to the acquisition or issue of financial assets or financial liabilities that are not held for trading are added to the fair value of such assets or liabilities at time of initial recognition.

Derivative Financial Instruments

In conducting its business, the Corporation may use various instruments, including forward contracts, swaps and options, to manage the risks arising from fluctuations in exchange rates, interest rates and commodity prices. All such instruments are used only to manage risk and not for trading purposes.

CICA recommendations require the recognition and measurement of derivative instruments embedded in host contracts that were issued, acquired or substantively modified on or after January 1, 2003. Derivative instruments embedded in host contracts that were issued, acquired or substantively modified prior to January 1, 2003, have not been identified and recognized in the consolidated financial statements as permitted by the recommendations.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

The Corporation designates each derivative instrument as either a hedging instrument or a non-hedge derivative:

(b) A hedging instrument is designated as either:
  (i) a fair value hedge of a recognized asset or liability or,
  (ii) a cash flow hedge of either:
    - a specific firm commitment or anticipated transaction or,
    - the variable future cash flows arising from a recognized asset or liability.

  At inception of a hedge, the Corporation documents the relationship between the hedging instrument and the hedged item, including the method of assessing retrospective and prospective hedge effectiveness. At the end of each period, the Corporation assesses whether the hedging instrument has been highly effective in offsetting changes in fair values or cash flows of the hedged item and measures the amount of any hedge ineffectiveness. The Corporation also assesses whether the hedging instrument is expected to be highly effective in the future.

  A hedging instrument is recorded on the consolidated balance sheet at fair value. Payments or receipts on a hedging instrument that is determined to be highly effective as a hedge are recognized concurrently with, and in the same financial category as, the hedged item. Subsequent changes in the fair value of a fair value hedge are recognized in earnings concurrently with the hedged item. For a cash flow hedge, the effective portion of changes in fair value is recognized in other comprehensive income and is subsequently transferred to earnings concurrently with the hedged item, whereas the portion of the changes in fair value that is not effective at offsetting the hedged exposure is recognized in earnings.

  If a hedging instrument ceases to be highly effective as a hedge, is de-designated as a hedging instrument or is settled prior to maturity, then the Corporation ceases hedge accounting prospectively for that instrument; for a cash flow hedge, the gain or loss deferred to that date remains in accumulated other comprehensive income and is transferred to earnings concurrently with the hedged item. Subsequent changes in the fair value of that derivative instrument are recognized in earnings.

  If the hedged item is sold, extinguished or matures prior to the termination of the related hedging instrument, or if it is probable that an anticipated transaction will not occur in the originally specified time frame, then the gain or loss deferred to that date for the related hedging instrument is immediately transferred from accumulated other comprehensive income to earnings.

  Hedge gains or losses that were recognized in other comprehensive income are added to the initial carrying amount of a non-financial asset or non-financial liability when:
  (i) an anticipated transaction for a non-financial asset or non-financial liability becomes a specific firm commitment for which fair value hedge accounting is applied or,
  (ii) a cash flow hedge of an anticipated transaction subsequently results in the recognition of the non-financial asset or non-financial liability.

(b) A non-hedge derivative instrument is recorded on the consolidated balance sheet at fair value and subsequent changes in fair value are recorded in earnings.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Employee Future Benefits

The Corporation accrues for its obligations under defined benefit pension and other post employment benefit ("OPEB") plans. Costs of these benefits are determined using the projected benefits method prorated on service and reflects management's best estimates of investment returns, wage and salary increases, age at retirement and expected health care costs.

Pension plan assets at the end of the year are reported at market value. The expected long term rate of return on plan assets is determined at the beginning of the year on the basis of the long bond yield rate at the beginning of the year plus an equity and management premium that reflects the plan asset mix.

Expected return on plan assets for the year is calculated by applying the expected long term rate of return to the market related value of plan assets, which is the average of the market value of plan assets at the end of the preceding three years.

Accrued benefit obligations at the end of the year are determined using a discount rate that reflects market interest rates on high quality corporate bonds that match the timing and amount of expected benefit payments.

Experience gains and losses and the effect of changes in assumptions in excess of 10% of the greater of the accrued benefit obligations or the market value of plan assets at the beginning of the year, adjustments resulting from plan amendments and the net transitional liability or asset, which arose upon the adoption in 2000 of the current accounting standard, are amortized over the estimated average remaining service life of employees.

Pursuant to an AUC decision effective January 1, 2000, the Utilities are required to expense contributions for other post employment benefit and defined benefit pension plans as paid. The difference between the amounts accrued and paid is deferred in non-current regulatory assets.

Employer contributions to the defined contribution pension plans are expensed as paid.

Stock Based Compensation Plans

The Corporation expenses stock options granted on and after January 1, 2002; no compensation expense is recorded for stock options granted prior to January 1, 2002, as permitted by GAAP. The Corporation determines the fair value of the options on the date of grant using an option pricing model and recognizes the fair value over the vesting period of the options granted as compensation expense and contributed surplus. Contributed surplus is reduced as the options are exercised and the amount initially recorded in contributed surplus is credited to Class A and Class B share capital.

No compensation expense is recognized when share appreciation rights are granted. Prior to vesting, compensation expense arising from an increase or decrease in the market price of the shares over the base value of the rights is accrued equally over the remaining months to the date of vesting. After that date, compensation expense arising from an increase or decrease in the market price of the shares is recognized in earnings.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Foreign Currency Translation

Assets and liabilities of self-sustaining foreign operations are translated into Canadian dollars at the rate of exchange in effect at the balance sheet date and revenues and expenses are translated at the average monthly rates of exchange during the year. Gains or losses on translation of self-sustaining foreign operations are included in accumulated other comprehensive income in share owners' equity.

Monetary assets and liabilities of integrated foreign operations, as well as non-monetary assets carried at market value, are translated into Canadian dollars at the rate of exchange in effect at the balance sheet date. Other non-monetary assets and non-monetary liabilities are translated at rates of exchange in effect when the assets were acquired or liabilities incurred. Revenues and expenses are translated at the average monthly rates of exchange during the year; depreciation and amortization are translated at rates of exchange consistent with the assets to which they relate. Gains or losses on translation of integrated foreign operations are recognized in earnings.

Transactions that are denominated in foreign currencies are translated at the rate of exchange in effect at the transaction date. Monetary items and non-monetary items that are carried at market value arising from a transaction denominated in a foreign currency are adjusted to reflect the rate of exchange in effect at the balance sheet date. Gains or losses on translation of such monetary and non-monetary items are recognized in earnings.

2. ACCOUNTING FOR RATE REGULATED OPERATIONS

Nature and economic effects of rate regulation

The Utilities are regulated primarily by the AUC. The AUC administers acts and regulations covering such matters as rates, financing, accounting, and service area.

The Utilities are subject to a cost of service regulatory mechanism under which the AUC establishes the revenues required (i) to recover the forecast operating costs, including depreciation and amortization and income taxes, of providing the regulated service, and (ii) to provide a fair return on utility investment, or rate base. Whereas actual operating conditions may vary from forecast, actual returns achieved can differ from approved returns.

Rate base for each utility is the aggregate of the AUC approved investment in property, plant and equipment and intangible assets, less accumulated depreciation and amortization, reserves for future removal and site restoration, and unamortized contributions by utility customers for extensions to plant, plus an allowance for working capital. The Utilities earn a return on rate base intended to meet the cost of the debt and preferred share components of rate base and to provide share owners with a fair return on the common equity component of rate base.

2. ACCOUNTING FOR RATE REGULATED OPERATIONS (continued)

The AUC approves rates of return for the debt and preferred share components of rate base based on the actual or forecast weighted average cost of each utility's debt and preferred shares and establishes the capital structure for each utility. Further details with respect to return on equity, capitalization and the generic cost of capital decisions from the AUC are included in Note 3.

Under the cost of service methodology, the Utilities seek approval for their revenue requirement either through submission of general rate applications to the AUC or a negotiated settlement process with interested parties. In the latter case, the AUC monitors the negotiated settlement process and any agreement that is reached is subject to AUC approval. The AUC may approve interim rates or approve the recovery of costs on a placeholder basis, subject to final determination.

The Battle River and Sheerness generating plants of Alberta Power (2000) were regulated by the AUC until December 31, 2000, but are now governed by legislatively mandated PPAs that were approved by the AUC. These plants are considered regulated operations primarily because the PPAs are designed to allow the owners of generating plants constructed before January 1, 1996 to recover their forecast fixed and variable costs and to earn a return at the rate specified in the PPAs. Each plant will become deregulated upon the earlier of one year after the expiry of its PPA or a decision to continue to operate the plant. For PPAs expiring prior to 2019, Alberta Power (2000) has one year after the expiry of a PPA to determine whether to decommission the generating plant in order to fully recover plant decommissioning costs or to continue to operate the plant and be responsible for the decommissioning costs. For PPAs expiring after 2018, decommissioning costs are the responsibility of the plant owner. Each PPA is to remain in effect until the earlier of the last day of the estimated life of the related generating plant or December 31, 2020.

Financial statement effects of rate regulation

Circumstances in which rate regulation affects the accounting for a transaction or event are described below. For these regulatory items, the expected recovery or settlement period, or likelihood of recovery or settlement, is affected by risks and uncertainties relating to the ultimate authority of the regulator in determining the item's treatment for rate setting purposes, and, unless specifically indicated, is indeterminate.

2. ACCOUNTING FOR RATE REGULATED OPERATIONS (continued)

The regulatory assets and liabilities comprise the following:

	2010	2009
Regulatory assets – current:		
Deferred electricity cost recoveries[(1)]	**$ -**	$ 16.1
Deferral of unused vacation costs[(2)]	**10.4**	14.5
Deferred load balancing transactions[(3)]	**5.8**	5.0
Other regulatory assets	**0.7**	1.8
	$ 16.9	$ 37.4
Regulatory assets – non-current:		
Future income tax recoveries[(4)]	**$361.4**	$299.2
Regulatory other post employment benefits asset (Note 21)[(5)]	**56.3**	51.3
Deferred electricity cost recoveries[(1)]	**16.8**	-
Deferred load balancing transactions[(3)]	**3.7**	14.4
Deferred hearing costs[(6)]	**10.6**	9.9
Other regulatory assets	**11.9**	9.1
	$460.7	$383.9
Regulatory liabilities – current:		
Deferred electricity costs[(1)]	**$ 2.1**	$ -
Deferred load balancing transactions[(3)]	**1.4**	18.1
Deferral of temperature impact on revenues[(7)]	**-**	4.0
Negotiated settlement deferrals[(8)]	**8.0**	-
Other regulatory liabilities	**5.5**	4.0
	$ 17.0	$ 26.1
Regulatory liabilities – non-current:		
Reserves for future removal and site restoration[(9)]	**$436.2**	$402.4
Regulatory pension liability (Note 21)[(5)]	**160.5**	120.9
Deferred pension recoveries[(10)]	**21.9**	-
Deferred royalty credits[(11)]	**11.8**	16.8
Deferral of temperature impact on revenues[(7)]	**12.1**	10.5
Deferred electricity costs[(1)]	**12.1**	6.1
Other regulatory liabilities	**11.5**	14.5
	$666.1	$571.2

[(1)] Deferred electricity costs (recoveries)

Variances between ATCO Electric's actual and forecast transmission access payments may arise due to changes in tariffs charged by the Alberta Electric System Operator ("AESO"). The amount included in customer rates is based on forecast cost. Revenues are adjusted for changes in tariffs, and the variances are deferred until approval from the AUC is obtained for refund to or collection from customers, which is expected to occur in the following year. GAAP requires that in the absence of rate regulation revenues be based on the rates approved by the AUC and not adjusted.

In Alberta, major transmission capital projects are planned by the AESO and directly assigned to one of the transmission facility owners in the province. Revenue requirement includes a return on forecast rate base. Whereas actual capital costs may vary from forecast capital costs, variances may arise between the return on forecast rate base and the return on actual rate base. Revenues are adjusted for these variances, and the variances are deferred until approval from the AUC is obtained for refund to or collection from

the AESO, which is expected to occur in the following year. GAAP requires that in the absence of rate regulation revenues be based on the rates approved by the AUC and not adjusted.

Variances between ATCO Electric's actual and forecast income tax provision may arise due to changes in enacted and substantively enacted tax rates. The amount included in customer rates is based on forecast tax rates. Revenues are adjusted for changes in enacted and substantively enacted tax rates, and the variances are deferred until approval from the AUC is obtained for refund to or collection from customers, which is expected to occur in the following year. GAAP requires that in the absence of rate regulation revenues be based on customer rates approved by the AUC and not adjusted.

Consequently, revenues in 2010 would have been $7.4 million higher (2009 – $10.5 million higher) in the absence of rate regulation.

(2) Deferral of unused vacation costs

Revenue requirement includes a recovery from customers for vacation entitlement taken by employees during the year. A portion of the vacation entitlement is earned by employees and accrued as a liability in the prior year. GAAP requires that in the absence of rate regulation the vacation pay liability be expensed in the year accrued and not deferred for amounts that will be recovered from customers. Consequently, expenses for 2010 would have been $4.1 million lower (2009 - $0.2 million lower) in the absence of rate regulation.

(3) Deferred load balancing transactions

ATCO Gas and ATCO Pipelines have received AUC approval to establish deferral accounts to collect the costs and revenues arising from load balancing transactions. Load balancing requires the purchase or sale of natural gas to maintain appropriate operating pressures on ATCO Gas' and ATCO Pipelines' North and South distribution and transmission pipeline systems.

Should the deferral account for either ATCO Gas' North or South systems exceed $2.0 million over three successive months, ATCO Gas may submit an application to the AUC requesting recovery from or refund to customers of that particular deferral account. As a result of an AUC decision received on December 14, 2009, the requirements to submit an application were prospectively changed to amounts exceeding $5 million over six successive months or $10 million for one month.

Should the deferral account for ATCO Pipelines' North or South systems exceed $2.0 million, ATCO Pipelines may submit an application to the AUC requesting recovery from or refund to customers of that particular deferral amount. On January 29, 2009, a decision was received that increased the amounts to $7.5 million for the North and $5.0 million for the South.

GAAP requires that in the absence of rate regulation actual revenues and costs be recognized in the period in which they are earned or incurred. Consequently, expenses in 2010 would have been $14.4 million lower and revenues in 2010 would have been $26.1 million lower (2009 – $23.3 million higher expenses and $4.3 million higher revenues) in the absence of rate regulation.

2. ACCOUNTING FOR RATE REGULATED OPERATIONS (continued)

(4) *Future income tax recoveries*

The Corporation recognizes future income tax assets and liabilities as well as a separate regulatory asset or liability for the amount of future income taxes expected to be included in future rates and recovered from or paid to future customers in the utility operations. GAAP requires that in the absence of rate regulation future income taxes be expensed in the period in which they are incurred and not deferred for amounts that will be recovered from or paid to customers. Consequently, expenses in 2010 would have been $62.2 million higher (2009 – $43.6 million higher) in the absence of rate regulation.

(5) *Employee future benefits*

The Corporation accrues for its obligations under defined benefit pension and other post employment benefit plans. The regulatory asset (liability) reflects an AUC decision, effective January 1, 2000, to record costs of employee future benefits in the Utilities when paid rather than accrued. The variances between the amounts paid and accrued for each of the defined benefit pension plans and the other post employment benefit plans will vary depending on the performance of plan assets and the actuarial valuations of plan obligations. These variances will be deferred until the plans are paid, settled or terminated.

GAAP requires that the variances between the amounts accrued and paid be recognized as an expense or reduction in expense in the period in which they are accrued. Consequently, defined benefit pension plan cost in 2010 would have been $7.4 million higher (2009 – $10.4 million lower), and other post employment benefit plan cost in 2010 would have been $2.9 million higher (2009 – $2.4 million higher) in the absence of rate regulation.

Upon the adoption of the current accounting standard in 2000, the Utilities had recorded deferred pension assets of $23.0 million. The Utilities have been earning an AUC approved rate of return on these assets through customer rates as the assets form part of the Utilities' AUC approved rate base. In the absence of rate regulation, the Utilities would not be able to earn a return on these assets. Consequently, revenues in 2010 would have been $0.8 million lower (2009 – $0.8 million lower). On October 11, 2006, the AUC issued a decision that approved recovery of these assets for a nine-year period commencing January 1, 2005, and permitted the Utilities to continue to earn an AUC approved rate of return on the unrecovered portion of these assets over the recovery period. In 2010, the Utilities amortized $3.7 million (2009 – $3.9 million) of the deferred pension asset.

(6) *Deferred hearing costs*

The Utilities incur hearing costs on an ongoing basis associated with various AUC regulatory proceedings. These costs are comprised primarily of legal and consulting expenses incurred by the Utilities in addition to costs incurred by intervener groups that have been reimbursed by the Utilities as directed by the AUC. The Utilities have received approval to defer the variances between actual hearing costs incurred and AUC approved forecast hearing costs collected through customer rates. Hearing costs are expensed as actual costs are incurred and revenues are adjusted for variances between the approved annual amounts and actual costs. The variances are deferred until the next general rate application or until a specific application is made to the AUC requesting recovery from or refund to customers. GAAP requires that in the absence of rate regulation, revenues be based on the rates approved by the AUC and not adjusted for variances between approved annual amounts and actual costs and that hearing costs be expensed in the period in which they are incurred. Consequently, revenues in 2010 would have been $0.7 million lower (2009 - $1.5 million lower) in the absence of rate regulation.

2. ACCOUNTING FOR RATE REGULATED OPERATIONS (continued)

(7) Deferral of temperature impact on revenues

ATCO Gas has received AUC approval to establish deferral accounts to mitigate the impact of temperature fluctuations on its revenues. Should the deferral account for either the North or the South exceed $7.0 million at April 30th of any year, ATCO Gas will submit an application to the AUC requesting recovery from or refund to customers of that particular deferral account. Costs related to financing these deferred amounts will be charged monthly to these deferral accounts based on ATCO Gas' weighted average cost of capital. GAAP requires that in the absence of rate regulation the temperature impacted revenues be recognized in the period in which they are realized. Consequently, revenues in 2010 would have been $2.4 million lower (2009 – $11.8 million higher) in the absence of rate regulation.

(8) Negotiated settlement deferrals

ATCO Pipelines received AUC approval for its 2010-2012 Revenue Requirement Settlement Application in May 2010, resulting in new deferral accounts fixing revenues, property taxes, and the amount of costs spent on the integration of ATCO Pipelines system with that of NOVA Gas Transmission Ltd. ("NOVA") at the levels included in the application. The deferrals are to be refunded or collected from customers in the following year. GAAP requires that in the absence of rate regulation, actual revenues and costs be recognized in the period in which they are earned or incurred. Consequently, revenues in 2010 would have been $8.0 million higher in the absence of rate regulation.

(9) Reserves for future removal and site restoration

The reserves for future removal and site restoration costs for the Utilities is established based on an annual amount approved by the AUC to be collected through customer rates and is recorded in non-current regulatory liabilities. Actual removal and site restoration costs are expensed as incurred and revenues are adjusted for variances between approved annual amounts and actual costs. The variances are deferred as reserves for future removal and site restoration costs. GAAP requires that in the absence of rate regulation, revenues be based on the rates approved by the AUC and not adjusted for variances between the provision incorporated into rates and actual costs. Consequently, revenues in 2010 would have been $33.8 million higher (2009 - $26.2 million higher) in the absence of rate regulation.

(10) Deferred pension recoveries

The Utilities requested and received AUC approval to recover from customers amounts contributed in 2010 to the Canadian Utilities pension plan. The contributions are recorded as expense or are capitalized to property, plant and equipment as the funding is incurred. As these amounts are recovered from customers, revenues are adjusted by the amount capitalized to property, plant and equipment. These adjustments are deferred as a regulatory liability and amortized to earnings on the same basis as the property, plant and equipment to which they relate. GAAP requires that in the absence of rate regulation revenues be based on the rates approved by the AUC. Consequently, revenues in 2010 would have been $21.9 million higher in the absence of rate regulation.

2. ACCOUNTING FOR RATE REGULATED OPERATIONS (continued)

(11) Deferred royalty credits

Under the terms of PPAs, the compensation for certain royalties incurred by Alberta Power (2000) for coal supply are averaged over the term of each PPA. As such, royalty costs are expensed on the same average cost basis as reflected in the underlying PPA revenues. GAAP requires that in the absence of rate regulation royalty costs be expensed in the period in which they are incurred. Consequently, expenses in 2010 would have been $5.0 million higher (2009 - $6.5 million higher) in the absence of rate regulation.

Other items affected by rate regulation

The AUC permits an allowance for funds used ("AFU"), based on each utility's weighted average cost of capital, to be included in rate base. AFU is also included in the cost of property, plant and equipment for financial reporting purposes, and is depreciated as part of the total cost of the related asset, based on the expectation that depreciation expense, including the AFU component, will be approved for inclusion in future customer rates. Since AFU includes preferred share and common equity components, it exceeds the amount allowed to be capitalized in similar circumstances in the absence of rate regulation. During the year, the Corporation capitalized $20.0 million (2009 – $23.4 million) relating to AFU.

The Corporation capitalized costs in accordance with the PPAs which would otherwise have been expensed. At December 31, 2010, $98.5 million (2009 – $96.5 million) was included in property, plant, and equipment relating to these costs which are being depreciated over the life of the plants. In the absence of rate regulation these costs would have been expensed to earnings at the time incurred.

3. REGULATORY MATTERS

Generic Cost of Capital

On November 12, 2009, the AUC issued its decision on the 2009 Generic Cost of Capital proceeding. In this decision, the AUC set the 2009 and 2010 generic return on equity ("ROE") at 9.0% for all Alberta utilities which it regulates. The AUC has maintained the concept of a single generic ROE for all utilities, with differences in utility or sector specific risk to be recognized through the adjustments of individual common equity ratios. The AUC determined the common equity ratio to be 36% for ATCO Electric's transmission operations, 39% for both ATCO Electric's distribution operations and ATCO Gas' operations and 45% for ATCO Pipelines' operations.

As part of the same decision, the AUC also set the 2011 generic return on equity at 9.0% on an interim basis subject to change following a subsequent generic proceeding. On December 16, 2010, the AUC initiated a 2011 Generic Cost of Capital proceeding, the scope of which includes, among other things, a full review of cost of capital matters including capital structure and the ROE for 2011. It will also include consideration of whether a formula approach to ROE can be reinstated for 2012. In the absence of a formula approach to ROE, the AUC will then consider how the ROE will be set for 2012. The proceeding is scheduled to be completed in the third quarter of 2011 and a decision is expected in the fourth quarter of 2011.

3. REGULATORY MATTERS (continued)

Pension Hearing

In July 2009, the Utilities submitted an application to the AUC requesting recovery of the expected 2010 contributions to the Canadian Utilities pension plan. Prior to 2010, there had been no required contributions since 1996. The Utilities also requested the establishment of deferral accounts due to projected funding requirements and the potential for fluctuations in pension asset values and resulting funding requirements. A hearing was held in January 2010 and an AUC decision was issued on April 30, 2010, approving the requested funding and establishing deferral accounts for funding fluctuations beyond the control of the Utilities. This decision did not result in a material change in the Utilities' earnings.

On December 15, 2010, the Utilities submitted an application supporting the pension methodology, specifically the determination of the cost of living allowance provision, used in the determination of pension costs included in the 2011 and future years' revenue requirements of the Utilities. The AUC expanded the scope of the application so that it will also be the basis to determine the 2011/2012 pension cost recovery for the Utilities. The application is a result of a directive issued by the AUC in the pension decision issued on April 30, 2010. A decision is expected in the fourth quarter of 2011.

Benchmarking

On March 8, 2010, the AUC issued a decision on the hearing held in December 2009 which addressed the 2003 – 2007 placeholder amounts for the pricing of services provided by ATCO I-Tek to the Utilities. The AUC decision approved the adjustments to the placeholder amounts as filed based on fair market value resulting in no material change to earnings. For the 2008 and 2009 period, a separate regulatory process has been established to approve rates for information technology and customer care and billing services provided by ATCO I-Tek that can be included in customer rates. The proceeding is scheduled to be completed in the first quarter of 2011 and a decision is expected in the second quarter of 2011. A further regulatory process to deal with rates for information technology and customer care and billing services provided by ATCO I-Tek for 2010 and beyond has been established and the AUC is expected to set a schedule for this regulatory process after the completion of the 2008 – 2009 process.

Company Specific Decisions

ATCO Electric

In May 2010, ATCO Electric filed a general tariff application with the AUC for 2011 and 2012 requesting, among other things, increased revenues to recover increased financing, depreciation, and operating costs associated with increased rate base in Alberta. The application also requested that construction work in progress for projects that are directly assigned from the AESO be included in rate base. This request would not impact earnings but would improve cash flow during the construction of the major transmission projects currently being undertaken. A decision is expected in the second quarter of 2011.

On July 2, 2009, the AUC issued a decision on ATCO Electric's 2009 and 2010 general tariff application. The effect of the decision increased ATCO Electric's 2009 annual earnings primarily as a result of an increase in rate base. In the decision, the AUC used placeholders for 2009 and 2010 information technology and customer care and billing rates and pension costs. The respective placeholders were determined by the AUC as a result of the Generic Cost of Capital, Pension and Benchmarking decisions discussed above.

3. REGULATORY MATTERS (continued)

ATCO Gas

In December 2010, ATCO Gas filed a general rate application with the AUC for 2011 and 2012 requesting, among other things, increased revenues to recover increased financing, depreciation, and operating costs associated with increased rate base in Alberta. A decision is expected in the fourth quarter of 2011. ATCO Gas also filed an application requesting interim adjustable rates pending the AUC's decision on the general rate application. A decision on the interim adjustable rates application is expected in the first quarter of 2011.

Carbon Natural Gas Storage Facility

As a result of numerous regulatory and legal proceedings, ATCO Gas received approval from the AUC to remove its Carbon Facility from regulation. On December 16, 2009, a Review and Variance decision issued by the AUC confirmed the effective date of removing the Carbon Facility from regulation to be April 1, 2005. On October 19, 2010, the AUC released the Carbon Compliance decision, approving a recovery from customers of $43.7 million plus interest in the amount of $5.9 million to September 30, 2010. Through numerous regulatory processes, ATCO Gas previously recorded revenues and earnings of $13.8 million and $9.9 million, respectively, in 2009. On April 20, 2010, ATCO Gas received a decision from the AUC approving, on an interim adjustable basis, the implementation of Carbon recovery riders resulting in an increase in ATCO Gas' revenues and earnings of $15.7 million and $11.3 million, respectively. In the third quarter of 2010, ATCO Gas recognized the remaining amounts pertaining to the Carbon Compliance application and related decision issued by the AUC resulting in an increase in ATCO Gas' revenues, interest income and earnings of $14.2 million, $5.9 million, and $14.5 million, respectively.

ATCO Gas filed an application with the AUC on December 1, 2010, to approve the internal transfer of the Carbon Facility to ATCO Midstream. The transaction is subject to the completion of documentation and receipt of all necessary approvals, including regulatory approval, in a form satisfactory to the Board of Directors of Canadian Utilities Limited. The transaction is expected to be completed in the second quarter of 2011.

Deferred Gas Account

ATCO Gas filed an application with the AUC to address, among other things, corrections required to historical transportation imbalances (the process whereby third party natural gas supplies are reconciled to amounts actually shipped in a corporation's pipelines) that have impacted ATCO Gas' deferred gas account. In April 2005, the AUC issued a decision resulting in a 15% decrease in the transportation imbalance adjustments sought by ATCO Gas. The decision resulted in ATCO Gas recovering $9.2 million in natural gas supply costs from customers.

The City of Calgary's appeal with respect to this decision was heard by the Alberta Court of Appeal on January 13, 2010. On April 23, 2010, the Alberta Court of Appeal issued a decision allowing the appeal and vacating orders under appeal and returned the matter to the AUC for consideration. The AUC completed a process to address the Alberta Court of Appeal decision and on October 15, 2010, issued a decision requiring ATCO Gas to refund to customers approximately 85% of the transportation imbalance adjustment amounts in question resulting in a refund of approximately $9.7 million, including interest of $1.7 million, and a decrease in ATCO Gas' 2010 earnings of $7.1 million.

3. REGULATORY MATTERS (continued)

ATCO Pipelines

Alberta System Integration

In 2009, ATCO Pipelines filed an application with the AUC for the integration of ATCO Pipelines' and NOVA's gas transmission systems in Alberta (Integration Application), and filed a second application with the AUC to approve its 2010, 2011 and 2012 negotiated settlement, which was a condition precedent of the Integration Application. The Integration Application requested the AUC to approve that (i) integration is in the public interest, (ii) ATCO Pipelines approved revenue requirements be charged to NOVA, (iii) ATCO Pipelines customers be transitioned to NOVA, with NOVA as the customer commercial point of contact, and (iv) ATCO Pipelines and NOVA swap assets in order to establish operating areas. A negotiated settlement on ATCO Pipelines' 2010, 2011 and 2012 revenue requirements was a condition precedent of the Integration Application. A settlement on ATCO Pipelines' 2010, 2011 and 2012 revenue requirements was successfully negotiated with interested parties on October 28, 2009. On November 12, 2009, ATCO Pipelines filed a request with the AUC to approve its 2010, 2011 and 2012 Revenue Requirement Settlement Application as part of its Integration Application.

The AUC issued a decision on May 27, 2010 approving integration and the 2010, 2011 and 2012 negotiated settlement but requested ATCO Pipelines to submit subsequent applications to address the specific details on: (i) the transition of ATCO Pipelines' customers to NOVA, and (ii) the asset swap between ATCO Pipelines and NOVA in order to establish operating areas. ATCO Pipelines has submitted an application to the AUC to address the transition of customers and a decision is expected in the second quarter of 2011. An application to address the asset swap will be submitted to the AUC in the first quarter of 2011.

4. TRANSACTION TO COMBINE ATCO FRONTEC, ATCO STRUCTURES AND ATCO NOISE MANAGEMENT

On July 1, 2009, the Corporation and its parent corporation, ATCO Ltd., finalized a transaction combining ATCO Frontec, a wholly-owned subsidiary of the Corporation, with ATCO Structures and ATCO Noise Management, both wholly-owned subsidiaries of ATCO Ltd ("ATCO Structures & Logistics Transaction"). As a result of this transaction, the Corporation and ATCO Ltd. have direct ownership interests of 24.5% and 75.5%, respectively, in the new company named ATCO Structures & Logistics. The ownership interests reflect the proportion of the respective valuations of the combined entities. The valuations were based on analysis prepared by independent financial advisors retained by the special committees of the Boards of Directors of the Corporation and ATCO Ltd.

4. TRANSACTION TO COMBINE ATCO FRONTEC, ATCO STRUCTURES AND ATCO NOISE MANAGEMENT (continued)

This is a related party transaction by entities under common control and has been accounted for at the exchange amount by the Corporation, with an after tax gain for accounting purposes of $29.6 million recorded on closing. Prior to the ATCO Structures & Logistics Transaction, the Corporation consolidated ATCO Frontec. Therefore, all revenues, expenses, assets and liabilities were recognized on a line-by-line basis in the consolidated financial statements of the Corporation for the period up to June 30, 2009. From July 1, 2009, the Corporation accounts for its 24.5% interest in ATCO Structures & Logistics on the equity basis as it retains significant influence. This is reflected as a single line item called "Earnings from investment in ATCO Structures & Logistics" on the consolidated statement of earnings and a single line item called "Investment in ATCO Structures & Logistics" on the consolidated balance sheet. The Investment in ATCO Structures & Logistics is increased or decreased to include the Corporation's share of earnings and capital transactions from July 1, 2009, onward.

The Corporation's investment in ATCO Structures & Logistics is as follows:

Investment at July 1, 2009	$121.8
Share of earnings	7.8
Share of other comprehensive income	(1.8)
Dividends received	(5.9)
Investment at December 31, 2009	**121.9**
Share of earnings	**19.7**
Share of other comprehensive income	**1.2**
Dividends received	**(4.9)**
Investment at December 31, 2010	**$137.9**

5. INTEREST AND OTHER INCOME

	2010	2009
Interest	**$ 20.8**	$ 22.6
Allowance for funds used by regulated operations	**20.0**	23.4
Gains (losses) on dispositions of property, plant and equipment	**2.7**	(0.3)
Unrealized loss on natural gas purchase contracts derivative asset (Note 22)	**(26.7)**	(34.1)
Unrealized gain on power generation revenue contract liability (Note 22)	**18.9**	24.2
Cash flow hedge gains	**1.3**	2.1
Other	**2.3**	5.4
	$ 39.3	$ 43.3

6. INCOME TAXES

The income tax provision differs from that computed using the statutory tax rates for the following reasons:

	2010		2009	
Earnings before income taxes	**$587.7**	%	$632.7	%
Income taxes, at statutory rates	**$164.6**	**28.0**	$183.5	29.0
ATCO Pipelines settlement	**(4.4)**	**(0.7)**	-	-
H.R. Milner income tax reassessment	-	-	(7.8)	(1.2)
Removal of Carbon storage assets from regulation	-	-	5.8	0.9
Benefit of purchased United Kingdom tax pools	-	-	(2.4)	(0.4)
Future income taxes relating to regulated operations (see Note 2)	**(46.5)**	**(8.0)**	(36.7)	(5.8)
Non-taxable portion of gain on ATCO Structures & Logistics transaction	-	-	(4.3)	(0.7)
Earnings from investment in ATCO Structures & Logistics	**(5.5)**	**(0.9)**	(2.3)	(0.4)
Foreign tax rate variance	**0.5**	**0.1**	(0.7)	(0.1)
Other	**0.5**	**0.1**	(9.7)	(1.5)
	109.2	**18.6**	125.4	19.8
Current income taxes	**102.7**		114.7	
Future income taxes	**$ 6.5**		$ 10.7	

The future income tax liabilities (assets) comprise the following:

	2010	2009
Property, plant and equipment	**$549.5**	$501.3
Intangibles	**50.6**	51.8
Deferred assets and liabilities	**(47.8)**	(71.2)
Tax loss carryforwards	**(17.6)**	(17.4)
Derivative financial instruments	**(0.2)**	1.1
Other	**4.2**	5.9
	538.7	471.5
Less: Current future income tax asset	**(2.0)**	(6.6)
	$540.7	$478.1

In 2010, ATCO Pipelines successfully negotiated a settlement with the Canada Revenue Agency ("CRA") regarding the classification of certain compressor assets for the years 2000 through 2004. The result of this settlement is a reduction in tax expense of $4.4 million and $0.7 million of related interest income.

On August 21, 2009, Alberta Power (2000) received a judgment from the Tax Court of Canada ordering CRA to reverse its 2006 reassessment of Alberta Power (2000)'s 2001 tax return for the sale of the H.R. Milner generating plant. On September 30, 2009, the appeal period for the judgment elapsed without an appeal from CRA. The impact of the judgment was a $7.8 million recovery of income tax and $5.9 million of related interest expense reassessed by CRA in 2006. In addition, Alberta Power (2000) received interest income of approximately $3.1 million earned on such amounts paid to CRA. These adjustments resulted in a $16.8 million increase in earnings for 2009. In total, Alberta Power (2000) received refunds of approximately $28.0 million, including interest, and net of consequential adjustments to other taxation years arising from the judgment.

6. INCOME TAXES (continued)

In 2009, ATCO Gas removed the Carbon storage assets from regulation (see Note 3). As a result, the Corporation recorded future income taxes of $5.8 million.

ATCO Power has tax loss carryforwards of $49.4 million for which it has recorded an income tax benefit. Approximately 88% of the losses expire in 2014 and 2015, with the remaining amounts expiring in 2029 and 2030. ATCO Electric has a tax loss carryforward of $19.7 million for which it has recorded a tax benefit. The loss expires in 2030.

Income taxes paid amounted to $93.2 million (2009 — $122.2 million).

7. INVENTORIES

	2010	2009
Natural gas and fuel in storage	**$21.9**	$23.5
Raw materials and consumables	**60.1**	56.3
	$82.0	$79.8

For the year ended December 31, 2010, the amount of inventories recognized as an expense was $70.5 million (2009 – $73.6 million). There have been $0.2 million write-downs to net realizable value and there have been no reversals of previous write-downs to net realizable value.

No inventories are pledged as security for liabilities.

8. PROPERTY, PLANT AND EQUIPMENT

		2010		2009	
	Composite Depreciation Rates	**Cost**	**Accumulated Depreciation**	Cost	Accumulated Depreciation
Utilities	2.7%	**$ 8,819.4**	**$2,555.1**	$ 8,157.4	$2,396.7
Energy	3.7%	**3,104.4**	**1,463.1**	3,194.0	1,372.8
Corporate & Other	9.5%	**92.6**	**55.9**	88.6	50.4
		$12,016.4	**4,074.1**	$11,440.0	3,819.9
Property, plant and equipment less accumulated depreciation			**7,942.3**		7,620.1
Unamortized contributions by utility customers for extensions to plant			**906.0**		887.4
			$7,036.3		$6,732.7

Composite depreciation rates reflect total depreciation in the year as a percentage of mid-year cost, excluding construction work-in-progress of $310.7 million (2009 — $376.8 million) and non-depreciable assets of $63.3 million (2009 — $55.3 million).

9. INTANGIBLES

	2010		2009	
	Cost	**Accumulated Amortization**	Cost	Accumulated Amortization
Computer software	**$333.7**	**$187.2**	$314.3	$170.3
Land rights	**130.9**	**23.4**	115.0	22.1
Other	**11.9**	**6.7**	11.4	6.2
	$476.5	**217.3**	$440.7	198.6
Intangibles less accumulated amortization		**259.2**		242.1
Unamortized contributions by utility customers		**0.1**		0.3
		$259.1		$241.8

Amortization expense relating to intangibles was $30.4 million (2009 – $23.5 million).

10. OTHER ASSETS

	2010	2009
Accrued pension asset (Note 21)	**$185.9**	$141.6
Security deposits for debt	**15.7**	17.0
Lease receivables	**197.1**	57.8
Other	**34.8**	27.6
	$433.5	$244.0

Lease receivables

During 2010 the two unit 86 MW natural gas-fired simple cycle generating plant in Karratha, Western Australia ("the Karratha plant"), commenced commercial operations. Due to the nature of the contract governing the Karratha plant's revenues, GAAP requires that this agreement be accounted for as a finance lease (with the Corporation as the lessor). The total net investment in the finance lease is equal to the present value of the minimum lease payments receivable.

As this lease is considered a sales-type finance lease for accounting purposes, $129.8 million was recorded in revenues to recognize the fair value of the lease receivable. These revenues were offset by $124.8 million in operation and maintenance expense associated with the construction costs of the two units which were removed from construction work in progress. This transaction resulted in an increase in earnings of $3.5 million for 2010.

11. BANK INDEBTEDNESS AND LINES OF CREDIT

At December 31, 2010, the Corporation has the following lines of credit that enable it to obtain financing for general business purposes:

	2010			2009		
	Total	**Used**	**Available**	Total	Used	Available
Long term committed	**$326.0**	**$ 3.0**	**$323.0**	$326.0	$48.0	$278.0
Short term committed	**600.0**	**35.8**	**564.2**	600.0	32.0	568.0
Uncommitted	**53.7**	**7.6**	**46.1**	63.7	7.0	56.7
	$979.7	**$46.4**	**$933.3**	$989.7	$87.0	$902.7

All of the $46.4 million used at December 31, 2010, represents outstanding letters of credit.

12. LONG TERM DEBT AND NON-RECOURSE LONG TERM DEBT

Long term debt

	Effective Interest Rate	**2010**	2009
Canadian Utilities			
CU Inc. debentures – unsecured			
1990 Series 11.40% due August 2010	11.537%	**$ -**	$ 125.0
2000 7.05% due June 2011	7.130%	**100.0**	100.0
2007 4.883% due November 2012	4.990%	**35.0**	35.0
2004 5.096% due November 2014	5.162%	**100.0**	100.0
2002 6.145% due November 2017	6.217%	**150.0**	150.0
2004 5.432% due January 2019	5.492%	**180.0**	180.0
1999 6.8% due August 2019	6.861%	**300.0**	300.0
1990 Second Series 11.77% due November 2020	11.903%	**100.0**	100.0
2006 4.801% due November 2021	4.854%	**160.0**	160.0
1991 Series 9.92% due April 2022	10.063%	**125.0**	125.0
1992 Series 9.40% due May 2023	9.511%	**100.0**	100.0
2009 6.215% due March 2024	6.278%	**120.0**	120.0
2008 5.563% due May 2028	5.614%	**125.0**	125.0
2004 5.896% due November 2034	5.939%	**200.0**	200.0
2005 5.183% due November 2035	5.226%	**185.0**	185.0
2006 5.032% due November 2036	5.072%	**160.0**	160.0
2007 5.556% due October 2037	5.598%	**220.0**	220.0
2008 5.580% due May 2038	5.622%	**200.0**	200.0
2009 6.500% due March 2039	6.550%	**150.0**	150.0
2010 4.947% due November 2050	4.988%	**125.0**	-
CU Inc. other long term obligation, due June 2012, unsecured	3.000%	**4.5**	4.5
Canadian Utilities Limited debentures – unsecured			
2002 6.14% due November 2012	6.228%	**100.0**	100.0
Less: Deferred financing charges		**(14.3)**	(15.3)
		2,925.2	2,924.2

12. LONG TERM DEBT AND NON-RECOURSE LONG TERM DEBT (continued)

Long term debt (continued)

	Effective Interest Rate	**2010**	2009
ATCO Midstream Ltd. credit facility, at BA rates, due June 2013, unsecured (1)	Floating	-	25.0
ATCO Power Canada Ltd. credit facility, at BA rates, due August 2013, secured by a pledge of cash (1)	Floating	-	22.0
ATCO Power Australia credit facility, payable in Australian dollars, at Bank Bill rates, due June 2015, secured by a pledge of project assets and contracts ($98.1 million AUD (2009 – $100.0 million AUD))	Floating (2)	**99.9**	94.4
Canadian Utilities Limited non-revolving credit facility at 5.72%, due June 2014	5.884%	**38.5**	39.5
		3,063.6	3,105.1
Less: Amounts due within one year		**3.3**	2.8
		$3,060.3	$3,102.3

Non-recourse long term debt

Project Financing	Effective Interest Rate	**2010**	2009
Barking Power Limited payable in British pounds:			
Term loans, at fixed rates averaging 7.95%, due to 2010 (2009 – £6.6 million)	7.95%	**$ -**	$ 11.2
Osborne Cogeneration Pty Ltd., payable in Australian dollars:			
Term loan, at Bank Bill rates, due to 2013 (1) ($17.9 million AUD (2009 – $22.1 million AUD))	Floating (2)	**18.2**	20.9
ATCO Power Alberta Limited Partnership ("APALP"):			
Term loan, at LIBOR, due to 2013 (1)	Floating (2)	**6.3**	30.1
Joffre:			
Term loan, at BA rates, due to 2012 (1)	Floating (2)	**0.1**	0.2
Term facility, at Canadian Prime Advances, due to 2012 (1)	Floating (2)	**0.1**	0.1
Term loan, at LIBOR, due to 2012 (1)	Floating (2)	**0.3**	0.5
Notes, at fixed rate of 8.59%, due to 2020	8.845%	**32.0**	32.0
Scotford:			
Term loan, at BA rates, due to 2014 (1)	Floating (2)	**22.6**	27.5
Term facility, at Canadian Prime Advances, due to 2014 (1)	Floating (2)	**0.1**	0.3
Term loan, at LIBOR, due to 2014 (1)	Floating (2)	**5.7**	7.0
Notes, at fixed rate of 7.93%, due to 2022	8.302%	**22.3**	23.4

12. LONG TERM DEBT AND NON-RECOURSE LONG TERM DEBT (continued)

***Non-recourse long term debt** (continued)*

Project Financing	Effective Interest Rate	**2010**	2009
Muskeg River:			
Term loan, at BA rates, due to 2014 [(1)]	Floating [(2)]	**18.3**	22.4
Term facility, at Canadian Prime Advances, due to 2014 [(1)]	Floating [(2)]	**0.2**	0.1
Term loan, at LIBOR, due to 2014 [(1)]	Floating [(2)]	**4.6**	5.6
Notes, at fixed rate of 7.56%, due to 2022	7.902%	**22.1**	23.9
Brighton Beach:			
Term loan, at BA rates, due to 2020 [(1)]	Floating [(2)]	**16.1**	17.2
Term loan, at LIBOR, due to 2020 [(1)]	Floating [(2)]	**14.5**	15.5
Construction overrun facility, at BA rates, due to 2020 [(1)]	Floating [(2)]	**3.9**	4.2
Construction overrun facility, at LIBOR, due to 2020 [(1)]	Floating [(2)]	**3.6**	3.8
Notes, at fixed rate of 6.924%, due to 2024	7.025%	**95.0**	98.5
Cory:			
Cost overrun facility, at BA rates, due to 2011 [(1)]	Floating [(2)]	**0.6**	1.2
Notes, at fixed rate of 7.586%, due to 2025	7.872%	**31.6**	33.0
Notes, at fixed rate of 7.601%, due to 2026	7.880%	**28.4**	29.5
Less: Deferred financing charges		**(5.5)**	(4.3)
		341.1	403.8
Less: Amounts due within one year		**38.3**	49.0
		$302.8	$354.8

BA – Bankers' Acceptance
LIBOR – London Interbank Offered Rate

(1) The above interest rates have additional margin fees at a weighted average rate of 1.5% (2009 — 1.2%). The margin fees are subject to escalation.
(2) Floating interest rates have been partially or completely hedged with interest rate swaps (see Note 22).

The non-recourse long term debt is secured by charges on the projects' assets and by an assignment of the projects' bank accounts, outstanding contracts and agreements. The book value of the pledged assets and bank accounts at December 31, 2010, was $859.6 million (2009 — $1,095.1 million).

Guarantees

Canadian Utilities Limited has provided a number of guarantees related to ATCO Power's obligations under non-recourse loans associated with certain of its projects. These guarantees cover the following items:

a) **Project cash flows** — Represents annual payments related to maintaining base case margins for electricity prices on the merchant power component of the project, being 24 megawatts ("MW") for the Scotford project and 48 MW for the Muskeg River project. These guarantees became effective upon the commercial operation of the plants and exist until 2022, when the project debt is to be fully repaid. The amounts payable under these guarantees will vary each year depending on the pool price received for the merchant power generated. Any payments made to maintain the project base case margins will either be available for distribution to the owners or be applied to mandatory prepayment

of the project debt in accordance with the terms of the project financing agreement depending upon the specific operating results of the plant. At December 31, 2010, no amounts were outstanding under the guarantee.

b) **Reserve amounts** — Represents amounts to be set aside for major maintenance and debt service reserves as stipulated in the project's financing agreement. These reserves are intended to be funded with project cash flows. To the extent that project cash flows are insufficient to meet reserve requirements, Canadian Utilities Limited may choose to provide guarantees in lieu of ATCO Power providing security. At December 31, 2010, the amount of the obligations under these guarantees is:

Project	Major Maintenance	Debt Service
APALP project financing	Nil [1]	$6.2
Brighton Beach project financing	Nil [2]	Nil
Cory project financing	Nil [1]	$4.0
Joffre project financing	Nil [1]	$1.5
Muskeg River project financing	Nil [1]	$4.9
Scotford project financing	Nil [1]	$5.2

[1] *No major maintenance reserve required for this financing.*
[2] *Reserve requirements of $0.1 million met with project cash flows.*

c) **Prepaid operating and maintenance fee** — Should ATCO Power cease to be operator of the APALP generating plants as a result of a termination of the operating agreement, Canadian Utilities Limited has guaranteed the payment of the unamortized portion of the prepaid operating and maintenance fee to APALP, the proceeds of which are to be used to repay project debt in accordance with the project financing agreements. This guarantee, which declines by $1.2 million per year, remains in effect until 2011, when the project debt is to be fully repaid. At December 31, 2010, the maximum value of the guarantee is $25.2 million.

d) **Purchase project assets** — Represents an obligation to purchase the Scotford and Muskeg River projects at a price sufficient to repay any outstanding project debt upon the occurrence of any one of the following very limited events:

(i) where all of the following events have occurred:
- the insolvency of ATCO Power;
- the failure of the project debt lenders to complete a sale of the project pursuant to their security within a fixed period of time; and
- the project purchaser of electricity and steam elects to terminate its purchase contracts due to the insolvency of ATCO Power;

(ii) where the project purchaser of electricity and steam does not remove ATCO Power as operator of the project after an event of default under the project financing agreements in circumstances where such default is either:
- a deliberate or willful breach of a project financing agreement; or
- where ATCO Power has failed to co-operate with the lenders in a sale of the project; and

(iii) where the project purchaser of electricity and steam terminates its purchase contracts for the project as a result of a default by ATCO Power's project minority joint venturers. ATCO Power has the right to cure any such default by acquiring the minority interest which is in default.

These guarantees remain in effect until the project debt is fully repaid. At December 31, 2010, no such events have occurred.

12. LONG TERM DEBT AND NON-RECOURSE LONG TERM DEBT (continued)

ATCO Power (80%) and ATCO Resources (20%), a wholly owned subsidiary of Canadian Utilities Limited's parent corporation, ATCO Ltd., have a joint venture in the above projects subject to guarantees, excluding Barking Power.

The foregoing guaranteed amounts represent ATCO Power's 80% interest. Canadian Utilities Limited has also guaranteed similar obligations in respect of ATCO Resources' 20% interest. ATCO Ltd. has indemnified and agreed to reimburse Canadian Utilities Limited for any amounts it may be required to pay under these guarantees in respect of ATCO Resources' 20% interest. ATCO Ltd.'s indemnification to reimburse Canadian Utilities Limited for any amounts payable under ATCO Resources 20% interest was cancelled effective January 1, 2011, when ATCO Resources was transferred to ATCO Power (see Note 26).

To date, Canadian Utilities Limited has not been required to pay any of its guaranteed obligations.

Contractual maturities of debt

The undiscounted contractual maturities of long term debt and non-recourse long term debt are as follows:

	Long Term Debt		Non-Recourse Long Term Debt		Total	
	Principal	Interest[(1)]	Principal	Interest[(1)]	Principal	Interest[(1)]
2011	$ 103.3	$ 188.7	$ 38.3	$ 22.1	$ 141.6	$ 210.8
2012	143.0	185.1	33.6	20.0	176.6	205.1
2013	3.8	176.8	35.7	18.0	39.5	194.8
2014	138.6	175.5	33.1	15.9	171.7	191.4
2015	89.1	166.6	20.7	14.3	109.8	180.9
2016 and thereafter	2,600.0	2,048.1	185.2	56.7	2,785.2	2,104.8
	$3,077.8	$2,940.8	$ 346.6	$ 147.0	$3,424.4	$3,087.8

(1) Interest payments on floating rate debt that has not been hedged have been estimated using rates in effect at December 31, 2010. Interest payments on debt that has been hedged have been estimated using the hedged rates.

Of the $141.6 million due in 2011, $100.0 million is to be refinanced with new debt or from existing unused long term credit lines and is, therefore, excluded from long term debt due within one year in the balance sheet.

Interest expense

Interest expense is as follows:

	2010	2009
Long term debt	**$199.5**	$203.8
Non-recourse long term debt	**27.4**	31.8
Bank indebtedness	**3.5**	2.5
Amortization of deferred financing charges	**3.8**	3.5
Other	**1.7**	-
	$235.9	$241.6

Interest paid amounted to $237.1 million (2009 — $233.4 million).

13. DEFERRED CREDITS

	2010	2009
Accrued other post employment benefits liability (Note 21)	**$ 69.8**	$ 64.2
Deferred availability incentives	**48.2**	67.1
Asset retirement obligations	**86.9**	83.2
Power generation revenue contract liability (Note 22)	**1.5**	20.4
Liability to customers for refund of future income taxes	**-**	12.1
Other	**30.7**	30.3
	$237.1	$277.3

Deferred availability incentives

Amortization of deferred availability incentives, which was recorded in revenues, amounted to $14.1 million (2009 – $16.3 million).

The amount to be amortized is dependent upon estimates of future generating unit availability and future electricity prices over the term of the PPAs. Each quarter, the Corporation uses these estimates to forecast the incentives to be received from, less penalties to be paid to, the PPA counterparties. These forecasts are added to the accumulated unamortized deferred availability incentives outstanding at the end of the quarter; the resulting total is divided by the remaining term of the PPA to arrive at the amortization for the quarter.

Asset retirement obligations

Changes in asset retirement obligations are summarized below:

	2010	2009
Obligations at beginning of year	**$ 83.2**	$77.7
Accretion expense	**4.4**	4.1
Obligations incurred	**2.6**	1.4
Revisions to estimates	**(3.3)**	-
Obligations at end of year	**$ 86.9**	$83.2

The Corporation estimates the undiscounted amount of cash flow required to settle the asset retirement obligations is approximately $148 million, which will be incurred between 2012 and 2052. The credit-adjusted risk-free discount rates used to calculate the fair value of the asset retirement obligations have a weighted average rate of 5.6%.

14. EQUITY PREFERRED SHARES

CU Inc. equity preferred shares

Authorized and issued

Authorized: An unlimited number of Series Preferred Shares, issuable in series.

Issued:

	Stated Value (dollars)	Redemption Dates	**2010** Shares	**2010** Amount	2009 Shares	2009 Amount
Cumulative Redeemable Preferred Shares						
4.60% Series 1	$25.00	See below	**4,600,000**	**$115.0**	4,600,000	$115.0
6.70% Series 2	$25.00	See below	**6,400,000**	**160.0**	6,400,000	160.0
3.80% Series 4	$25.00	See below	**3,000,000**	**75.0**	-	-
				$350.0		$275.0

On December 2, 2010, CU Inc., a subsidiary corporation, issued $75.0 million Cumulative Redeemable Preferred Shares Series 4 at a price of $25.00 per share. Holders of the Series 4 Preferred Shares will be entitled to receive, as and when declared by the Board of Directors of CU Inc., fixed cumulative preferential cash dividends, payable quarterly for an initial period of five years at an annual rate of $0.95 per share to yield 3.80% annually. Thereafter the dividend rate will reset every five years to the then current 5-Year Government of Canada bond yield plus 1.36%.

Fair values

Fair values for the CU Inc. Preferred Shares determined using quoted market prices for the same or similar issues are $358.3 million (2009 - $278.3 million).

Redemption privileges

The Series 1 preferred shares are redeemable at the option of the Corporation commencing on June 1, 2012, at the stated value plus a 4% premium per share for the next 12 months plus accrued and unpaid dividends. The redemption premium declines by 1% in each succeeding twelve month period until June 1, 2016.

On June 1, 2014, and on June 1 of every fifth year thereafter, CU Inc. may redeem the Series 2 Preferred Shares in whole or in part at par. Holders may elect to convert any or all of their Series 2 Preferred Shares into an equal number of Cumulative Redeemable Preferred Shares Series 3 on June 1, 2014, and on June 1 of every fifth year thereafter. Holders of the Series 3 Preferred Shares will be entitled to receive, as and when declared by the Board of Directors of CU Inc., floating rate cumulative preferential cash dividends, payable quarterly for an initial period of five years at a rate equal to the then current 3-month Government of Canada Treasury Bill yield plus 4.81%. On June 1, 2019, and on June 1 of every fifth year thereafter ("Series 3 Conversion Date"), holders of the Series 3 Preferred Shares may elect to convert any or all of their Series 3 Preferred Shares back into an equal number of Series 2 Preferred Shares. On June 1, 2014, or thereafter, CU Inc. may redeem the Series 3 Preferred Shares in whole or in part at $25.00 on a Series 3 Conversion Date or at $25.50 on any other date.

On June 1, 2016, and on June 1 of every fifth year thereafter, CU Inc. may redeem the Series 4 Preferred Shares in whole or in part at par. Holders may elect to convert any or all of their Series 4 Preferred

14. EQUITY PREFERRED SHARES (continued)

Shares into an equal number of Cumulative Redeemable Preferred Shares Series 5 on June 1, 2016, and on June 1 of every fifth year thereafter. Holders of the Series 5 Preferred Shares will be entitled to receive, as and when declared by the Board of Directors of CU Inc., floating rate cumulative preferential cash dividends, payable quarterly for an initial period of five years at a rate equal to the then current 3-month Government of Canada Treasury Bill yield plus 1.36%. On June 1, 2021, and on June 1 of every fifth year thereafter ("Series 5 Conversion Date"), holders of the Series 5 Preferred Shares may elect to convert any or all of their Series 5 Preferred Shares back into an equal number of Series 4 Preferred Shares. On June 1, 2016, or thereafter, CU Inc. may redeem the Series 5 Preferred Shares in whole or in part at $25.00 on a Series 5 Conversion Date or at $25.50 on any other date.

Canadian Utilities Limited equity preferred shares

Authorized and issued

Authorized: An unlimited number of Series Second Preferred Shares, issuable in series.

Issued:

	Stated Value	Redemption Dates	2010		2009	
			Shares	**Amount**	Shares	Amount
	(dollars)					
Cumulative Redeemable Second Preferred Shares						
5.8% Series W	$25.00	See below	**6,000,000**	**$150.0**	6,000,000	$150.0
6.0% Series X	$25.00	See below	**6,000,000**	**150.0**	6,000,000	150.0
Perpetual Cumulative Second Preferred Shares						
4.35% Series O	$25.00	December 2, 2011	**1,600,000**	**40.0**	1,600,000	40.0
4.35% Series T	$25.00	December 2, 2011	**1,600,000**	**40.0**	1,600,000	40.0
4.35% Series U	$25.00	December 2, 2011	**800,000**	**20.0**	800,000	20.0
4.70% Series V	$25.00	October 3, 2012	**4,400,000**	**110.0**	4,400,000	110.0
				$510.0		$510.0
Total CU Inc. and Canadian Utilities Limited equity preferred shares				**$860.0**		$785.0

The dividends payable on the Series O, T, U, and V preferred shares are fixed until the redemption dates specified above, at which time a new dividend rate may be established by negotiations between Canadian Utilities Limited and the owners of the shares.

Fair values

Fair values for the Canadian Utilities Limited preferred shares determined using quoted market prices for the same or similar issues are $519.5 million (2009 — $512.3 million).

Redemption privileges

The preferred shares, except for Series W and X, are redeemable on the dates specified above at the option of Canadian Utilities Limited at the stated value plus accrued and unpaid dividends. The Series W preferred shares are redeemable commencing on March 1, 2008, at the stated value plus a 4% premium for the next 12 months plus accrued and unpaid dividends. The redemption premium declines by 1% in each succeeding 12 month period until March 1, 2012.

14. EQUITY PREFERRED SHARES (continued)

The Series X preferred shares are redeemable commencing June 1, 2008, at the stated value plus a 4% premium for the next 12 months plus accrued and unpaid dividends. The redemption premium declines by 1% in each succeeding 12 month period until June 1, 2012.

15. CLASS A AND CLASS B SHARES

Authorized and issued

	Class A Non-Voting		Class B Common		Total	
	Shares	Amount	Shares	Amount	Shares	Amount
Authorized:	Unlimited		Unlimited			
Issued and outstanding:						
December 31, 2008	83,522,994	$389.0	41,987,126	$132.9	125,510,120	$521.9
Stock options exercised	349,550	6.4	-	-	349,550	6.4
Converted: Class B to Class A	268,736	0.8	(268,736)	(0.8)	-	-
December 31, 2009	**84,141,280**	**$396.2**	**41,718,390**	**$132.1**	**125,859,670**	**$528.3**
Purchased and cancelled	**(138,850)**	**(0.6)**	**-**	**-**	**(138,850)**	**(0.6)**
Stock options exercised	**209,350**	**5.4**	**-**	**-**	**209,350**	**5.4**
Converted: Class B to Class A	**1,753,612**	**5.6**	**(1,753,612)**	**(5.6)**	**-**	**-**
December 31, 2010	**85,965,392**	**$406.6**	**39,964,778**	**$126.5**	**125,930,170**	**$533.1**

From January 1, 2011, to February 18, 2011, 6,800 stock options were exercised, no stock options were granted or cancelled, 44,000 Class B common shares were converted to Class A non-voting shares, and 1,059,658 Class A non-voting shares and 489,171 Class B common shares were issued by the Corporation to ATCO Ltd. related to the transfer of ATCO Resources (see Note 26).

Earnings per share

Earnings per Class A non-voting and Class B common share is calculated by dividing the earnings attributable to Class A and Class B shares by the weighted average shares outstanding. Diluted earnings per share is calculated using the treasury stock method, which reflects the potential exercise of stock options on the weighted average Class A non-voting and Class B common shares outstanding. The average number of shares used to calculate earnings per share are as follows:

	Three Months Ended December 31		Year Ended December 31	
	2010	2009	**2010**	2009
	(Unaudited)			
Weighted average shares outstanding	**125,892,718**	125,752,093	**125,850,797**	125,637,206
Effect of dilutive stock options	**161,243**	156,676	**120,625**	137,044
Weighted average dilutive shares outstanding	**126,053,961**	125,908,769	**125,971,422**	125,774,250

15. CLASS A AND CLASS B SHARES (continued)

Share owner rights

The owners of the Class A non-voting shares and the Class B common shares are entitled to share equally, on a share for share basis, in all dividends declared by Canadian Utilities Limited on either of such classes of shares as well as the remaining property of Canadian Utilities Limited upon dissolution. The owners of the Class B common shares are entitled to vote at shareholder meetings and to exchange at any time each share held for one Class A non-voting share.

If a take-over bid is made for the Class B common shares which would result in the offeror owning more than 50% of the outstanding Class B common shares and which would constitute a change in control of Canadian Utilities Limited, owners of Class A non-voting shares are entitled, for the duration of the bid, to exchange their Class A non-voting shares for Class B common shares and to tender such Class B common shares pursuant to the terms of the take-over bid. Such right of exchange is conditional upon the completion of the take-over bid giving rise to the right of exchange, and if the take-over bid is not completed, then the right of exchange shall be deemed never to have existed. In addition, owners of the Class A non-voting shares are entitled to exchange their shares for Class B common shares of Canadian Utilities Limited if ATCO Ltd., the present controlling share owner of Canadian Utilities Limited, ceases to own or control, directly or indirectly, more than 10,000,000 of the issued and outstanding Class B common shares of Canadian Utilities Limited. In either case, each Class A non-voting share is exchangeable for one Class B common share, subject to changes in the exchange ratio for certain events such as a stock split or rights offering.

Normal course issuer bid

On March 1, 2010, Canadian Utilities Limited commenced a normal course issuer bid for the purchase of up to 3% of the outstanding Class A shares. The bid will expire on February 28, 2011. From March 1, 2010, to February 18, 2011, 138,850 shares were purchased, all of which were in 2010, for $6.5 million and resulted in a decrease to share capital and retained earnings, respectively, of $0.6 million and $5.9 million.

16. CAPITAL DISCLOSURES

The Corporation's objectives when managing capital have been:

1. to safeguard the ability to continue as a going concern, so that it can continue to provide returns to share owners and benefits for other stakeholders;
2. to maintain an appropriate credit rating in order to provide efficient and cost effective access to funds required for operations and growth; and
3. to remain within the capital structure approved by the AUC for the Utilities.

The Corporation includes share owners' equity, equity preferred shares, long term debt and non-recourse long term debt in its determination of capitalization. In managing its capital, the Corporation considers both the regulated and non-regulated operations in the consolidated group as well as changes in economic conditions and risks impacting the core assets and operations. In maintaining or adjusting its capital structure, the Corporation may adjust the amount of dividends paid to share owners, issue or purchase Class A and Class B shares, and issue or redeem equity preferred shares, long term debt and non-recourse long term debt.

16. CAPITAL DISCLOSURES (continued)

The Utilities are regulated primarily by the AUC, which, through the generic cost of capital decisions issued in 2004 and 2009, established the capital structure for each utility. The Utilities are capitalized consistent with the generic cost of capital decisions. The capitalization involves the use of long term debt and preferred share financings; the AUC approved the continued use of the latter in a decision issued in 2006.

While the Utilities have had an objective of being capitalized consistent with the AUC decisions, the Corporation itself is not restricted in its capital structure. The capital structure for the Corporation is set relative to risk and to meet the financial and operational objectives of the Corporation (while considering the decisions of the regulator).

Decisions on the level and type of financing are based on assessments by management in line with the Corporation's objectives. In determining the type of financing to be undertaken by a given operation, the Corporation has a goal of managing the financial risk to the Corporation as a whole.

Capital is monitored through an equity capitalization measure which is calculated as total equity divided by total capitalization. Total equity is comprised of Class A and Class B shares, contributed surplus, retained earnings, accumulated other comprehensive income and equity preferred shares. Total capitalization is comprised of long term debt, non-recourse long term debt and total equity. The Corporation's strategy has been to maintain the equity capitalization allowed by the regulator for the regulated operations and to structure the non-regulated operations so as to sustain access to cost effective financing by maintaining high credit ratings on debt and preferred shares. The Corporation looks to maintain an equity capitalization in the range of 45% to 55%.

Other measures that are taken into consideration are interest coverage and interest and preferred dividend coverage. Interest coverage is calculated by dividing earnings before income taxes, interest expense and dividends on equity preferred shares by total interest expense. Interest and preferred dividend coverage is calculated by dividing earnings before income taxes, interest expense and dividends on equity preferred shares by interest expense and dividends on equity preferred shares (grossed up to pre-tax equivalents). The Corporation looks to maintain interest coverage of at least 2.5 and interest and preferred dividend coverage of at least 2.0; these objectives are unchanged from 2009.

Equity capitalization, interest coverage and interest and preferred dividend coverage do not have any standardized meaning under GAAP and might not be comparable to similar measures presented by other companies.

16. CAPITAL DISCLOSURES (continued)

The Corporation's key measures of capital structure are as follows:

	2010	2009
Class A and Class B shares	$ 533.1	$ 528.3
Contributed surplus	1.2	3.2
Retained earnings	2,807.7	2,568.6
Accumulated other comprehensive income	(66.8)	(54.0)
Equity preferred shares	860.0	785.0
Total equity	4,135.2	3,831.1
Long term debt	3,060.3	3,102.3
Non-recourse long term debt	302.8	354.8
Total debt	3,363.1	3,457.1
Total capitalization	$7,498.3	$7,288.2
Equity capitalization	55%	53%

The equity capitalization is consistent with the Corporation's objectives. Total equity increased primarily due to higher earnings of the Corporation reflected in increased retained earnings and higher equity preferred shares due to the preferred share financing for utility capital expenditures. Total debt decreased primarily due to redemptions of long term debt and non-recourse long term debt.

	2010	2009
Interest coverage	3.5	3.5
Interest and preferred dividend coverage	2.8	2.8

For the year ended December 31, 2010, the Corporation was in compliance with externally imposed requirements on its capital (including debt covenants and credit facilities). The Corporation will continue to assess its capital structure and objectives in light of decisions received from the AUC.

17. STOCK BASED COMPENSATION PLANS

Stock option plan

Of the 6,400,000 Class A non-voting shares authorized for grant in respect of options under Canadian Utilities Limited's stock option plan, 2,946,200 Class A non-voting shares are available for issuance at December 31, 2010. Options may be granted to officers and key employees of Canadian Utilities Limited and its subsidiaries at an exercise price equal to the weighted average of the trading price of the shares on the Toronto Stock Exchange for the five trading days immediately preceding the date of grant. The vesting provisions and exercise period (which cannot exceed 10 years) are determined at the time of grant.

17. STOCK BASED COMPENSATION PLANS (continued)

Changes in shares under option are summarized below:

	2010		2009	
	Class A Shares	**Weighted Average Exercise Price**	Class A Shares	Weighted Average Exercise Price
Options at beginning of year	**871,900**	**$35.63**	1,238,250	$30.86
Granted	**53,000**	**47.29**	-	-
Exercised	**(209,350)**	**26.00**	(349,550)	18.19
Forfeited	**(9,700)**	**45.99**	(16,800)	46.40
Options at end of year	**705,850**	**$39.23**	871,900	$35.63

Information about stock options outstanding at December 31, 2010, is summarized below:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Class A Shares	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Class A Shares	Weighted Average Exercise Price
$24.52 - $28.65	71,050	1.8	$25.76	71,050	$25.76
$30.25 - $37.12	202,000	4.0	30.31	201,600	30.30
$43.49 - $47.84	432,800	6.5	45.60	221,300	45.31
$24.52 - $47.84	705,850	5.3	$39.23	493,950	$36.37

In 2010, Canadian Utilities Limited granted 53,000 options to purchase Class A non-voting shares at a weighted average exercise price of $47.29 per share. Options have a term of ten years and vest over the first five years.

Changes in contributed surplus are summarized below:

	2010	2009
Contributed surplus at beginning of year	**$3.2**	$2.6
Stock option expense	**0.3**	0.6
Mid-term incentive plan purchases	**(2.3)**	-
Contributed surplus at end of year	**$1.2**	$3.2

The Corporation uses the Black-Scholes option pricing model, which estimated the weighted average fair value of the options granted during 2010 at $6.66 per option (2009 – no options granted) based on the following weighted average assumptions:

	2010	2009
Risk free interest rate	2.8%	N/A
Expected holding period prior to exercise	8.4 years	N/A
Share price volatility	16.1%	N/A
Estimated annual Class A share dividend	3.1%	N/A

17. STOCK BASED COMPENSATION PLANS (continued)

Share appreciation rights

Directors, officers and key employees of the Corporation may be granted share appreciation rights that are based on Class A non-voting shares of Canadian Utilities Limited or Class I Non-Voting Shares of ATCO Ltd. The vesting provisions and exercise period (which cannot exceed 10 years) are determined at the time of grant. The base value of the share appreciation rights is equal to the weighted average of the trading price of the Class A non-voting shares and the Class I Non-Voting Shares, respectively, on the Toronto Stock Exchange for the five trading days immediately preceding the date of grant. The holder is entitled on exercise to receive a cash payment equal to any increase in the market price of the Class A non-voting shares and Class I Non-Voting Shares, respectively, over the base value of the share appreciation rights exercised.

Share appreciation rights expense amounted to $4.2 million (2009 — $1.1 million).

18. CHANGES IN NON-CASH WORKING CAPITAL

	2010	2009
Operating activities, changes related to:		
Accounts receivable	**$(42.2)**	$(24.4)
Inventories	**(0.2)**	13.8
Regulatory assets	**23.8**	23.0
Prepaid expenses	**(3.1)**	(4.8)
Accounts payable and accrued liabilities	**54.5**	(43.3)
Income taxes payable	**2.4**	(8.9)
Regulatory liabilities	**(9.1)**	(10.5)
	$26.1	$(55.1)
Investing activities, changes related to:		
Accounts receivable	**$ 2.7**	$ (3.9)
Inventories	**(2.6)**	4.1
Prepaid expenses	**(0.1)**	-
Accounts payable and accrued liabilities	**(3.1)**	(29.7)
	$(3.1)	$(29.5)

19. JOINT VENTURES

The Corporation's interest in joint ventures is summarized below:

	2010	2009
Statement of earnings		
Revenues	**$ 349.7**	$ 487.2
Operating expenses	**205.6**	281.2
Depreciation and amortization	**39.2**	46.7
Interest	**23.7**	26.9
	81.2	132.4
Interest and other income (loss)	**(3.4)**	(5.3)
Earnings from joint ventures before income taxes	**$ 77.8**	$ 127.1

19. JOINT VENTURES (continued)

	2010	2009
Balance sheet		
Current assets	**$ 114.0**	$ 112.7
Current liabilities	**(80.2)**	(90.2)
Property, plant and equipment	**730.8**	768.6
Other assets	**2.8**	27.3
Non-recourse long term debt	**(265.2)**	(288.3)
Other non-current liabilities	**(57.5)**	(71.0)
Investment in joint ventures	**$ 444.7**	$ 459.1
Statement of cash flows		
Operating activities	**$ 104.1**	$ 134.3
Investing activities	**(5.1)**	3.0
Financing activities	**(93.2)**	(150.5)
Foreign currency translation	**(2.6)**	(1.2)
Increase (decrease) in cash position	**$ 3.2**	$ (14.4)

Current assets include cash of $43.9 million (2009 — $38.8 million) which is only available for use within the joint ventures.

20. RELATED PARTY TRANSACTIONS

In transactions with ATCO Ltd. and its subsidiary corporations, the Corporation sold fuel in the amount of $1.4 million (2009 — $1.5 million), provided computer operations and systems development services totaling $5.0 million (2009 – $3.9 million), recovered administrative expenses totaling $2.4 million (2009 — $7.8 million) and incurred administrative expenses and corporate signature rights totaling $9.5 million (2009 — $8.8 million).

In transactions with entities related through common control, the Corporation incurred advertising, promotion and administrative expenses totaling $1.1 million (2009 — $1.4 million).

At December 31, 2010, accounts receivable due from related parties amounted to $7.0 million (2009 – $3.8 million) and accounts payable due to related parties amounted to $4.6 million (2009 – $3.5 million).

These transactions are in the normal course of business and under normal commercial terms, measured at the exchange amount.

21. EMPLOYEE FUTURE BENEFITS

The Corporation maintains registered defined benefit and defined contribution pension plans for most of its employees and provides other post employment benefits, principally health, dental and life insurance, for retirees and their dependants. The defined benefit pension plans provide for pensions based on employees' length of service and final average earnings. As of 1997, new employees automatically participate in the defined contribution pension plan and employees participating in the defined benefit pension plans may transfer to the defined contribution pension plan at any time. Upon transfer, further accumulation of benefits under the defined benefit pension plans ceases. The Corporation also maintains non-registered, non-funded defined benefit pension plans for certain officers and key employees.

21. **EMPLOYEE FUTURE BENEFITS** (continued)

Information about the Corporation's benefit plans, in aggregate, is as follows:

	2010		2009	
	Pension Benefit Plans	**Other Post Employment Benefit Plans**	Pension Benefit Plans	Other Post Employment Benefit Plans
Benefit plan assets, obligations and funded status				
Market value of plan assets:				
Beginning of year	**$1,530.8**	**$ -**	$1,399.1	$ -
Actual return on plan assets	**166.3**	**-**	190.1	-
Employee contributions	**3.2**	**-**	3.3	-
Employer contributions	**54.7**	**-**	1.0	-
Benefit payments	**(51.4)**	**-**	(47.7)	-
Payments to defined contribution plans [1]	**-**	**-**	(15.0)	-
End of year	**$1,703.6**	**$ -**	$1,530.8	$ -
Accrued benefit obligations:				
Beginning of year	**$1,521.2**	**$ 68.0**	$1,399.6	$ 57.8
Current service cost	**31.1**	**1.8**	25.9	1.7
Interest cost	**103.8**	**4.3**	93.6	4.2
Employee contributions	**3.2**	**-**	3.3	-
Benefit payments from plan assets [2]	**(51.4)**	**-**	(47.7)	-
Benefit payments by employer	**(5.1)**	**(1.8)**	(4.8)	(1.9)
Experience losses (gains) [3]	**303.7**	**7.2**	51.3	6.2
End of year [4]	**$1,906.5**	**$ 79.5**	$1,521.2	$ 68.0
Funded status:				
Excess (deficiency) of assets over obligations [4]	**$ (202.9)**	**$(79.5)**	$ 9.6	$(68.0)
Amounts not yet recognized in financial statements:				
Unrecognized net cumulative experience losses on plan assets and accrued benefit obligations	**474.1**	**(3.3)**	251.4	(10.6)
Unrecognized net transitional liability (asset)	**(85.3)**	**13.0**	(119.4)	14.4
Accrued asset (liability) (Notes 10, 13)	**$ 185.9**	**$(69.8)**	$ 141.6	$(64.2)
Regulatory asset (liability) [5] (Note 2)	**$ (160.5)**	**$ 56.3**	$ (120.9)	$ 51.3

(1) *Employer contributions for certain of the Corporation's defined contribution pension plans were paid from the assets of the defined benefit pension plans prior to 2010.*

(2) *Pension plan benefit payments are indexed to increases in the Canadian Consumer Price Index to a maximum increase of 3% per annum.*

(3) *Decrease in the liability discount rate assumption at December 31 resulted in the experience losses in 2010 and 2009.*

(4) *The non-registered, non-funded defined benefit pension plans accrued benefit obligations increased to $90.4 million at December 31, 2010, (2009 – $76.3 million) due to a decrease in the liability discount rate. Apart from these obligations, the deficiency of assets compared to obligations for the registered defined benefit pension plans at December 31, 2010, was $112.5 million (2009 – excess of assets over obligations of $85.9 million).*

(5) *The regulatory asset (liability) reflects an AUC decision to record costs of employee future benefits in the Utilities when paid rather than accrued.*

21. EMPLOYEE FUTURE BENEFITS (continued)

	2010		2009	
	Pension Benefit Plans	**Other Post Employment Benefit Plans**	Pension Benefit Plans	Other Post Employment Benefit Plans
Benefit plan cost				
Components of benefit plan cost:				
Current service cost	**$ 31.1**	**$ 1.8**	$ 25.9	$ 1.7
Interest cost	**103.8**	**4.3**	93.6	4.2
Actual return on plan assets	**(166.3)**	**-**	(190.1)	-
Experience losses on accrued benefit obligations	**303.7**	**7.2**	51.3	6.2
	272.3	**13.3**	(19.3)	12.1
Adjustments to recognize long term nature of employee future benefits:				
Unrecognized portion of actual return on plan assets	**63.7**	**-**	78.9	-
Unrecognized portion of experience gains on accrued benefit obligations	**(303.7)**	**(7.2)**	(51.3)	(6.2)
Amortization of net cumulative experience losses on plan assets and accrued benefit obligations	**17.3**	**(0.1)**	8.4	(0.4)
Amortization of net transitional liability (asset)	**(34.1)**	**2.0**	(34.1)	2.1
	(256.8)	**(5.3)**	1.9	(4.5)
Defined benefit plans cost (income)	**15.5**	**8.0**	(17.4)	7.6
Employer contributions by the Utilities [(1)]	**46.2**	**-**	-	-
Defined contribution plans cost	**16.4**	**-**	16.2	-
Total cost (income)	**78.1**	**8.0**	(1.2)	7.6
Less: Capitalized	**25.4**	**2.7**	1.8	2.4
Less: Unrecognized defined benefit plans cost (income) [(1)] [(2)]	**7.4**	**2.9**	(10.4)	2.4
Net cost recognized [(2)]	**$ 45.3**	**$ 2.4**	$ 7.4	$ 2.8

(1) *The unrecognized defined benefit plans cost (income) reflects an AUC decision to record costs of employee future benefits in the Utilities when paid rather than accrued.*

(2) *Net cost recognized for pension benefit plans in 2010 includes the amortization of $3.7 million (2009 – $3.9 million) of the deferred pension assets recorded by the Corporation upon the adoption of the current accounting standard in 2000. On October 11, 2006, the AUC approved recovery of these assets for a nine-year period commencing January 1, 2005 (Note 2).*

21. EMPLOYEE FUTURE BENEFITS (continued)

In the unaudited three months ended December 31, 2010, net expense of $9.3 million (2009 – $0.6 million) was recognized for pension benefit plans and net expense of $0.6 million (2009 – $0.6 million) was recognized for other post employment benefit plans. The net expense for the pension benefit plans includes a cash expense of $8.5 million related to the Utilities which is in accordance with the AUC decision to recover funding from customers.

Weighted average assumptions

	2010		2009	
	Pension Benefit Plans	**Other Post Employment Benefit Plans**	Pension Benefit Plans	Other Post Employment Benefit Plans
Assumptions regarding benefit plan cost:				
Expected long term rate of return on plan assets for the year	**7.0%**	-	7.5%	-
Liability discount rate for the year	**6.4%**	**6.4%**	7.0%	7.0%
Average compensation increase for the year	**(1)**	-	(1)	-
Assumptions regarding accrued benefit obligations:				
Liability discount rate at December 31	**5.6%**	**5.6%**	6.4%	6.4%
Long term inflation rate	**2.25%**	**(2)**	2.0%	(2)

(1) *The assumed average compensation increases are 3.75% until 2011 and 3.25% thereafter (2009 - 3.5% for 4 years (2009-2012) and 3.0% thereafter).*

(2) *The assumed annual health care cost trend rate increases used in measuring the accumulated post employment benefit obligation are as follows: for drug costs, 6.4% for 2010 grading down over 14 years to 4.5% (2009 – 6.5% for 2009 grading down over 15 years to 4.5%), for other medical costs, 4.5% for 2010 and thereafter (2009 - 4.5% for 2009 and 4.0% thereafter), and for dental costs, 4.0% for 2010 and thereafter (2009 – 4.0% for 2009 and thereafter).*

The sensitivities of key assumptions used in measuring accrued benefit obligations and benefit plan cost for 2010 are outlined in the following table. The sensitivities of each key assumption have been calculated independently of changes in other key assumptions. Actual experience may result in changes in a number of assumptions simultaneously.

	2010 Pension Benefit Plans		2010 Other Post Employment Benefit Plans	
	Accrued Benefit Obligation	Benefit Plan Cost	Accrued Benefit Obligation	Benefit Plan Cost
Expected long term rate of return on plan assets				
1% increase [1]	-	$(3.2)	-	-
1% decrease [1]	-	$ 3.2	-	-
Liability discount rate				
1% increase [1]	$(57.6)	$(4.6)	$(2.4)	$(0.3)
1% decrease [1]	$ 71.4	$ 5.3	$ 2.9	$ 0.1
Future compensation rate				
1% increase [1]	$ 11.8	$ 1.5	-	-
1% decrease [1]	$(11.3)	$(1.5)	-	-
Long term inflation rate				
1% increase [1] [2] [3]	$ 42.7	$ 5.1	$ 2.2	$ 0.2
1% decrease [1] [3]	$(48.9)	$(5.9)	$(1.9)	$(0.3)

(1) *Sensitivities are net of the associated regulatory asset (liability) and unrecognized defined benefit plans cost, which reflect an AUC decision to record costs of employee future benefits in the Utilities when paid rather than accrued.*

(2) *The long term inflation rate for pension plans reflects the fact that pension plan benefit payments are indexed to increases in the Canadian Consumer Price Index to a maximum increase of 3.0% per annum.*

(3) *The long term inflation rate for other post employment benefit plans is the assumed annual health care cost trend rate described in the weighted average assumptions.*

Pension benefit plan assets

	2010		2009	
	Amount	**%**	Amount	%
Plan asset mix:				
Equity securities [1]	**$ 945.9**	**55.5**	$ 842.6	55.0
Fixed income securities [2]	**636.1**	**37.4**	584.1	38.2
Real estate [3]	**90.7**	**5.3**	90.1	5.9
Cash and other assets [4]	**30.9**	**1.8**	14.0	0.9
	$1,703.6	**100.0**	$1,530.8	100.0

(1) *Equity securities consist of investments in domestic and foreign preferred and common shares. At December 31, 2010, the market values of investments in United States' securities and international equities, denominated in a number of different currencies, are $176.7 million and $173.7 million, respectively (2009 – $146.4 million and $151.1 million, respectively).*

(2) *Fixed income securities consist of investments in federal and provincial government and corporate bonds and debentures.*

(3) *Real estate consists of investments in closed-end real estate funds.*

(4) *Cash and other assets consist of cash, short term notes and money market funds.*

(5) *All of the plan assets have a fair value hierarchy of level 1 except for $311.8 million of fixed income securities and $18.6 million of real estate funds which are level 2 and $43.6 million of equity securities and $48.4 million of real estate funds which are level 3 (refer to Note 1 for hierarchy description).*

21. EMPLOYEE FUTURE BENEFITS (continued)

At December 31, 2010, plan assets include long term debt of CU Inc. having a market value of $13.8 million (2009 – $15.1 million), Class A non-voting and Class B common shares of Canadian Utilities Limited having a market value of $22.1 million (2009 – $17.8 million) and Class I Non-Voting Shares of ATCO Ltd. having a market value of $21.7 million (2009 – $17.0 million).

Funding

Employees are required to contribute a percentage of their salary to registered pension plans. The Corporation is required to contribute its share of contributions on behalf of the defined contribution members of the pension plans and to provide the balance of the funding necessary to ensure that benefits will be fully provided for at retirement for the members of the defined benefit pension plans.

Declines in stock and bond markets, changes in actuarial assumptions and additional employee service created funding deficits in the Corporation's defined benefit pension plans. Prior to 2010, the Corporation had not made material contributions since April 1, 1996, as a result of the defined benefit plans' surplus position. In addition, the Corporation had obtained regulatory approval to fund the employer's contributions to the defined contribution component of the pension plan from the defined benefit plan surplus.

Based on these changes, material current service and deficit funding contributions resumed in 2010. The actual funding contributions for 2010 were established based on actuarial valuations for funding purposes as of December 31, 2009. Based on these final actuarial valuations, the employer contributions relating to both the defined contribution and the defined benefit components of the plan for 2010 were approximately $71 million. Contributions commenced during the first quarter of 2010. The next actuarial valuation for funding purposes is required to be completed as of December 31, 2012.

For purposes of any pension funding requirements pertaining to utility operations, the AUC has directed that the cash basis of accounting be used in customer rate applications. Accordingly, the Corporation includes the cost of funding in its rate applications to the AUC, thereby, with the consent of the AUC, recovering approximately 78% of the costs of funding its pension plans from utility customers. The net funding contribution amounts (actual funding contributions less recovery from utility customers) were approximately $16 million.

22. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

The Corporation's Board of Directors ("Board") is responsible for understanding the principal risks of the business in which the Corporation is engaged, achieving a proper balance between risks incurred and the potential return to share owners, and confirming that there are systems in place that effectively monitor and manage those risks with a view to the long-term viability of the Corporation. The Board has established a Risk Review Committee, which reviews significant risks associated with future performance, growth and lost opportunities identified by management that could materially affect the Corporation's ability to achieve its strategic or operational targets. This committee is responsible for confirming that management has procedures in place to mitigate identified risks.

The Corporation is exposed to changes in interest rates, commodity prices and foreign currency exchange rates. The Energy Segment is affected by the cost of natural gas, the price of natural gas liquids and the price of electricity in the Province of Alberta and the United Kingdom. In conducting its business, the Corporation may use various instruments, including forward contracts, swaps and options, to manage the

risks arising from fluctuations in exchange rates, interest rates and commodity prices. All such instruments are used only to manage risk and not for trading purposes.

At December 31, 2010, the following derivative instruments were outstanding: interest rate swaps that hedge interest rate risk on the variable future cash flows associated with a portion of long term debt and non-recourse long term debt, forward power sales, forward gas purchases and greenhouse gas emission credit purchases to fix spark spreads for a portion of availability at the Barking Power Station and certain natural gas purchase contracts that were not considered own-use contracts.

The derivative assets and liabilities comprise the following:

	2010	2009
Derivative assets – current:		
Interest rate swap agreements	**$ 1.2**	$ 1.2
Forward gas purchase contracts	**1.2**	-
Greenhouse gas emissions credits purchase contracts	**0.5**	-
	$ 2.9	$ 1.2
Derivative assets – non-current:		
Interest rate swap agreements	**$ 4.3**	$ 5.4
Natural gas purchase contract	**1.5**	26.0
	$ 5.8	$31.4
Derivative liabilities – current:		
Interest rate swap agreements	**$ 1.7**	$ 2.4
Forward power sale contracts	**1.2**	-
Foreign currency forward swaps	**-**	0.5
	$ 2.9	$ 2.9
Derivatives liabilities – non-current:		
Interest rate swap agreements	**$ 3.9**	$ 5.9
Natural gas purchase contract	**2.2**	-
	$ 6.1	$ 5.9

Interest rate risk

The Corporation's interest-bearing assets and liabilities include cash and short-term investments, bank indebtedness, long term debt and non-recourse long term debt. The interest rate risk faced by the Corporation is largely a result of its non-recourse long term debt at variable rates and cash and short term investments. The Corporation has converted certain variable rate long term debt and non-recourse long term debt to fixed rate debt through the following interest rate swap agreements:

22. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS (continued)

Financing	Swap Fixed Interest Rate (1)	Variable Debt Interest Rate	Maturity Date	Notional Principal 2010	Notional Principal 2009
Karratha: ($98.1 million AUD (2009 – $100.00 million AUD))	6.160%	Bank Bill Rate in Australia	June 2015	**$ 99.8**	$ 94.4
Osborne: ($17.0 million AUD (2009 - $21.0 million AUD))	7.433%	Bank Bill Rate in Australia	December 2013	**17.3**	19.7
APALP:	7.750%	6 month LIBOR	December 2011	**18.2**	40.7
Joffre:	7.536%	90 day BA	September 2012	**7.3**	11.5
Scotford:	3.443%	90 day BA	November 2013	**22.8**	27.8
	3.840%	3 month LIBOR	November 2013	**5.7**	7.0
Muskeg River:	5.635%	90 day BA	December 2012	**18.6**	22.5
	5.753%	3 month LIBOR	December 2012	**4.6**	5.6
Brighton Beach:	6.700%	90 day BA	March 2019	**27.7**	30.0
	4.578%	90 day BA	June 2020	**4.0**	4.2
	4.784%	3 month LIBOR	June 2020	**3.6**	3.8
Cory:	6.711%	90 day BA	June 2011	**0.3**	0.9
				$229.9	$268.1

BA – Bankers' Acceptance
LIBOR – London Interbank Offered Rate

(1) *The above swap fixed interest rates include any long term debt margin fees; the margin fees are subject to escalation (Note 12).*

The Corporation has fixed interest rates, either directly or through interest rate swap agreements, on 96% (2009 — 95%) of total long term debt and non-recourse long term debt. Consequently, the exposure to fluctuations in future cash flows, with respect to debt, as a result of changes in market interest rates is limited. Interest rate swaps are designated as cash flow hedges; changes in the fair value of highly effective cash flow hedges, which include all but the Joffre and APALP interest rate swaps, are recorded in other comprehensive income. Changes in the fair value of the Joffre and APALP interest rate swaps were $0.4 million and $0.5 million (2009 – $0.7 million and $1.4 million), respectively, which were recognized in earnings as the interest rate swaps are ineffective.

The Corporation's cash and short term investments include fixed rate instruments with maturities of generally 90 days or less that are reinvested as they mature. The Corporation has exposure to interest rate movements that occur beyond the term of maturity of the fixed rate investments.

Foreign currency exchange rate risk

The Corporation has exposure to changes in the carrying values of its foreign operations, including assets and liabilities, as a result of changes in exchange rates. Gains or losses on translation of self-sustaining

foreign operations are included in the foreign currency translation adjustment account in accumulated other comprehensive income.

Foreign currency exchange rate risk arises from financial instruments denominated in a currency other than the functional currency. In 2009, the Corporation entered into foreign currency forward contracts in order to fix the exchange rate on certain service contracts, planned equipment expenditures and operational cash flows denominated in U.S. dollars. At December 31, 2010, the Corporation has no foreign currency forward contracts (2009 — purchases of $0.2 million U.S. in return for Canadian dollars and $2.8 million U.S. in return for Australian dollars).

Energy commodity price risk

On September 30, 2010, the Barking Power Station's long term power offtake contract expired. The contract covered 725 MW of the power stations capacity, of which the Corporation's share was 185 MW. A new tolling contract for 178 MW of the plant's capacity, of which the Corporation's share is 45 MW, was entered into for a one-year term commencing October 1, 2010. The balance of the plant's capacity is sold in the United Kingdom merchant electricity market via forward spark spread derivatives whereby power, natural gas and greenhouse gas emissions credits are simultaneously sold and purchased to secure spark spreads for future delivery.

Natural gas for the capacity under long term power purchase agreements is provided either under a long term supply agreement or is the responsibility of the offtaker. Natural gas for uncontracted capacity is purchased on a daily basis at spot prices or is purchased in the UK within the spark spread derivatives described above.

Inability to supply energy under certain long term power purchase agreements requires the Corporation to pay market prices for substitute energy.

Natural gas purchase contracts and associated power generation revenue contract liability

The Corporation has long term contracts for the supply of natural gas for certain of its power generation projects. Under the terms of certain of these contracts, the volume of natural gas that the Corporation is entitled to take is in excess of the natural gas required to generate power. As the excess volume of natural gas can be sold, the Corporation is required to designate these entire contracts as derivative instruments. The Corporation recognized a non-current derivative asset and liability and records mark-to-market adjustments through earnings as the fair values of these contracts change with changes in future natural gas prices. These natural gas purchase contracts mature in November 2014.

As all but the excess volume of natural gas is committed to the Corporation's power generation obligations, the Corporation could not recognize the entire fair values of these natural gas purchase contracts in its revenues. Consequently, the Corporation has recognized a provision for a power generation revenue contract and records adjustments to the power generation revenue contract liability concurrently with the mark-to-market adjustments for the natural gas purchase contracts derivative asset. This power generation revenue contract liability is included in deferred credits in the consolidated balance sheet.

22. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS (continued)

The mark-to-market adjustment for the derivative asset and liability and the corresponding adjustment for the associated power generation revenue contract liability decreased earnings by $2.0 million, for the unaudited three months ended December 31, 2010, (2009 – $2.0 million) and decreased earnings by $5.9 million, for the year ended December 31, 2010 (2009 – $7.4 million). At December 31, 2010, the natural gas purchase contract derivative asset is $1.5 million (2009 – $26.0 million), the natural gas purchase contract derivative liability is $2.2 million (2009 – nil), and the power generation revenue contract liability is $1.5 million (2009 – $20.4 million).

Credit risk

For cash and short term investments and accounts receivable, credit risk represents the carrying amount on the consolidated balance sheet. Cash and short term investments credit risk is reduced by investing in instruments issued by credit worthy financial institutions and in federal government issued short term instruments. Approximately 73% of the short term investments at December 31, 2010, were invested in Government of Canada treasury bills and certificates of deposit issued by Canadian financial institutions.

Derivative credit risk arises from the possibility that a counterparty to a contract fails to perform according to the terms and conditions of that contract. Derivative credit risk is minimized by dealing with large, credit-worthy counterparties in accordance with established credit approval policies.

Lease receivable credit risk arises from the possibility that a counterparty to a lease arrangement fails to make its lease payments according to the terms and conditions of that contract. Lease receivable credit risk is minimized by dealing with large, credit-worthy counterparties in accordance with established credit approval policies.

The maximum exposure to credit risk is the carrying value of loans and receivables and derivative financial instruments on the balance sheet. The Corporation does not have a concentration of credit risk with any counterparties, except for the lease receivables, which by their nature are with single counterparties. A significant portion of loans and receivables arise from the Corporation's operations in Alberta, with the exception of the lease receivable for the Karratha plant in Australia.

Accounts receivable credit risk is reduced by a large and diversified customer base, requirement for credit security such as letters of credit, and, for the Utilities the ability to recover an estimate for doubtful accounts through approved customer rates and the ability to request recovery through customer rates for any losses from retailers beyond that covered by the retailer security provided in accordance with provincial regulations.

22. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS (continued)

Accounts receivable are non-interest bearing and are generally due in 30 to 90 days. At December 31, 2010, the provision for impairment of credit losses was $1.2 million. The changes in the provision for impairment were as follows:

	2010
Provision at beginning of year	**$ 1.5**
Impairment of receivables	**(0.1)**
Receivables written off as uncollectible	**(0.2)**
Provision at end of year	**$ 1.2**

At December 31, 2010, the aging analysis of trade receivables that are past due but not impaired is as follows:

	2010	2009
30 to 90 days	**$3.7**	$1.7
Greater than 90 days	**0.8**	0.9
	$4.5	$2.6

No other impairments have been identified within accounts receivable.

Liquidity risk

Liquidity risk is the risk that the Corporation will not be able to meet its obligations associated with financial liabilities. Cash flow from operations provides a substantial portion of the Corporation's cash requirements. Additional cash requirements are met with the use of existing cash balances and externally through bank borrowings and the issuance of long term debt, non-recourse long term debt and preferred shares. Commercial paper borrowings and short term bank loans are used under available credit lines to provide flexibility in the timing and amounts of long term financing. The Corporation has a policy not to invest any of its cash balances in asset backed securities.

22. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS (continued)

The Corporation has contractual obligations in the normal course of business; future minimum undiscounted contractual maturities are as follows:

	2011	2012	2013	2014	2015	2016 and thereafter
Accounts payable and accrued liabilities	$ 404.9	$ -	$ -	$ -	$ -	$ -
Operating leases [1]	21.5	15.0	13.7	11.9	10.4	28.5
Long term debt (Note 12)	103.3	143.0	3.8	138.6	89.1	2,600.0
Non-recourse long term debt (Note 12)	38.3	33.6	35.7	33.1	20.7	185.2
Interest expense (Note 12)	210.8	205.1	194.8	191.4	180.9	2,104.8
Purchase obligations:						
Coal purchase contracts [2]	66.3	67.2	65.5	76.3	87.7	348.2
Natural gas purchase contracts [3]	13.2	13.4	7.0	0.2	-	-
Operating and maintenance agreements [4]	19.9	17.1	21.1	24.0	8.0	30.3
Capital expenditures [5]	88.3	-	-	-	-	-
Derivatives [6]	2.8	1.8	1.0	0.8	0.6	1.0
Other	9.0	8.4	7.9	2.8	0.3	0.2
	$978.3	$ 504.6	$ 350.5	$ 479.1	$ 397.7	$5,298.2

(1) *Operating leases are comprised primarily of long term leases for office premises and equipment.*
(2) *Alberta Power (2000) has fixed price long term contracts to purchase coal for its coal-fired generating plants.*
(3) *Natural gas purchase contracts consist primarily of ATCO Power contracts to purchase natural gas for certain of its natural gas-fired generating plants.*
(4) *ATCO Power and Alberta Power (2000) have long term service agreements with suppliers to provide operating and maintenance services at certain of their generating plants.*
(5) *Various contracts to purchase goods and services with respect to capital expenditures.*
(6) *Payments on outstanding derivatives have been estimated using rates in effect at December 31, 2010.*

22. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS (continued)

Fair value of non-derivative financial instruments

The carrying values and fair values of the Corporation's non-derivative financial instruments are as follows:

	2010		2009	
	Carrying Value	**Fair Value**	Carrying Value	Fair Value
Financial Assets				
Held For Trading:				
Cash [1]	**$ 134.4**	**$ 134.4**	$ 104.2	$ 104.2
Held to Maturity:				
Short term investments [1]	**405.2**	**405.2**	691.8	691.8
Loans and Receivables:				
Accounts receivable [1]	**407.9**	**407.9**	366.4	366.4
Lease receivables [2]	**197.1**	**197.1**	59.1	59.1
Financial Liabilities				
Other Liabilities:				
Accounts payable and accrued liabilities [3]	**404.9**	**404.9**	382.1	382.1
Liabilities to customers for future income taxes (see Note 13) [3]	**-**	**-**	12.1	12.1
Long term debt [4]	**3,063.6**	**3,531.7**	3,105.1	3,397.4
Non-recourse long term debt [4]	**341.1**	**386.6**	403.8	438.8

(1) *Recorded at cost. Fair value approximates the carrying amounts due to the short term nature of the financial instruments and negligible credit losses.*

(2) *Recorded at amortized cost. Fair value approximates the carrying amount as the lease receivable has been recorded at the present value of future minimum lease payments and negligible credit losses.*

(3) *Recorded at cost. Fair value approximates the carrying amounts due to the short term nature of the financial instruments.*

(4) *Recorded at amortized cost. Fair values are determined using quoted market prices for the same or similar issues. Where the market prices are not available, fair values are estimated using discounted cash flow analysis based on the Corporation's current borrowing rate for similar borrowing arrangements.*

22. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS (continued)

Fair value of derivative financial instruments

The fair values of the Corporation's derivative financial instruments are as follows:

	2010			2009		
	Notional Principal[1]	**Fair Value Receivable (Payable)[3]**	**Maturity**	Notional Principal[1]	Fair Value Receivable (Payable)[3]	Maturity
Held For Trading:						
Interest rate swaps	**$229.9**	**$ (0.1)**	**2011-2020**	$268.1	$ (1.7)	2010-2019
Foreign currency forward contracts	**$ -**	**$ -**	**-**	$ 3.4	$ (0.5)	2010
Natural gas purchase contracts	**N/A [2]**	**$(0.7)**	**2014**	N/A [2]	$26.0	2014
Forward power sales contracts	**N/A [2]**	**$(1.2)**	**2011**	-	$ -	$ -
Forward gas purchase contracts	**N/A [2]**	**$ 1.2**	**2011**	-	$ -	$ -
Greenhouse gas emissions credits purchase contracts	**N/A [2]**	**$ 0.5**	**2011**	-	$ -	$ -

(1) The notional principal is not recorded in the consolidated financial statements as it does not represent amounts that are exchanged by the counterparties.

(2) The notional amount for the natural gas purchase contracts is the maximum volumes that can be purchased over the terms of the contracts. The notional amount for the forward sale and purchase contracts are the commodity volumes committed in the contracts.

(3) Fair values for the interest rate swaps and the foreign currency forward contracts have been estimated using period-end market rates, and fair values for the natural gas purchase contracts have been estimated using period-end forward market prices for natural gas. These fair values approximate the amount that the Corporation would either pay or receive to settle the contract at December 31.

Fair value of financial instruments

The hierarchy of the Corporation's financial instruments measured at fair value is as follows (see Note 1 for description of hierarchy):

	Level 1	Level 2	Level 3	Total
Derivative assets	$ -	$7.2	$1.5	$8.7
Derivative liabilities	-	(6.8)	(2.2)	(9.0)
	$ -	$0.4	$(0.7)	$(0.3)

22. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS (continued)

Amounts included in Level 3 relate to the natural gas purchase contracts described previously. The changes in amounts classified in Level 3 are as follows:

	2010
Balance at beginning of year	$ 26.0
Total gains (losses) recognized in earnings	(26.7)
Balance at end of year	$ (0.7)

Sensitivity analysis

The analysis below illustrates the extent to which the Corporation's results are impacted by financial instruments and the underlying market risks (interest rate risk, foreign currency exchange risk, and commodity price risk). Non-derivative financial instruments (listed on the previous page) are recorded at cost and these carrying amounts are not affected by changes in market variables whereas carrying amounts of derivative financial instruments are affected by market variables.

The following table reflects the sensitivity in the fair value of outstanding derivative instruments to reasonably possible changes in Canadian and Australian interest rates, the foreign currency exchange rates of the Canadian dollar to the U.S. dollar, the Australian dollar to the U.S. dollar and the forward price of natural gas. The analysis excludes the impact that changes in the underlying market risks would have on non-financial assets and liabilities, foreign currency translation of self-sustaining foreign operations included in accumulated other comprehensive income, and carrying value of employee future benefits. Sensitivities are reflected in changes to earnings and other comprehensive income, after income taxes.

Assumptions made in arriving at the sensitivity analysis are as follows:

- Changes in the fair value of derivative instruments that are highly effective cash flow hedges from movements in interest rates or foreign currency exchange rates are recorded in other comprehensive income.
- Changes in the fair value of derivative instruments that are not designated as hedges, that are fair value hedges or that are ineffective cash flow hedges are recorded in earnings.
- Balance sheet sensitivity to interest rates and foreign currency exchange rates relates only to derivative instruments. There are no available for sale financial assets and other liabilities are carried at amortized cost, in which case the carrying values are not affected by changes in interest rates and foreign currency exchange rates.
- Changes in the forward price of natural gas affect the mark to market adjustment of the natural gas purchase contracts derivative asset and the corresponding adjustment for the associated power generation revenue contract liability.
- Changes in the forward prices of United Kingdom power sales, gas purchases and greenhouse gas emissions credits purchases comprising spark spread forward positions are recorded in earnings.
- Changes in the forward prices of greenhouse gas emissions credits in the United Kingdom for the advanced sales of allowances granted under the European Union Emissions Trading Scheme are recorded in earnings.

22. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS (continued)

	2010	
	Earnings	Other Comprehensive Income
Canadian interest rates		
25 basis points increase	$ -	$ 0.5
25 basis points decrease	$ -	$(0.5)
Australian interest rates		
25 basis points increase	$ -	$ 0.7
25 basis points decrease	$ -	$(0.7)
Forward price of natural gas		
10% increase	$ 5.1	$ -
10% decrease	$(6.7)	$ -
Forward price of power in the United Kingdom		
10% increase	$(0.8)	$ -
10% decrease	$ 0.8	$ -
Forward price of greenhouse gas emissions credits in Europe		
10% increase	$(0.5)	$ -
10% decrease	$ 0.5	$ -

23. OTHER COMPREHENSIVE INCOME

Other comprehensive income ("OCI") of the Corporation is comprised of two components: the unrealized gains and losses on effective cash flow hedging instruments and the foreign currency translation adjustment relating to self-sustaining foreign operations.

Changes in the components of accumulated OCI are summarized below:

	2010	2009
Accumulated OCI at beginning of period:		
Cash flow hedge losses (1)	**$ (3.0)**	$(11.5)
Foreign currency translation adjustment	**(51.0)**	(43.6)
	(54.0)	(55.1)
Adjustment to accumulated OCI from the ATCO Structures & Logistics Transaction:		
Cash flow hedge losses (2)	**-**	0.2
Foreign currency translation adjustment	**-**	(1.3)
	-	(1.1)
OCI for the period:		
Changes in fair values of cash flow hedges (3)	**0.3**	7.4
Transfers of cash flow hedge losses to earnings (4)	**1.1**	0.9
	1.4	8.3
Foreign currency translation adjustment	**(14.2)**	(6.1)
	(12.8)	2.2
Accumulated OCI at end of period:		
Cash flow hedge losses (5)	**(1.6)**	(3.0)
Foreign currency translation adjustment	**(65.2)**	(51.0)
	$(66.8)	$(54.0)

(1) *Net of income taxes of $1.0 million and $4.2 million, respectively.*
(2) *Net of income taxes of $(0.1) million.*
(3) *Net of income taxes of $(0.8) million and $(3.2) million, respectively.*
(4) *Net of income taxes of nil.*
(5) *Net of income taxes of $0.2 million and $0.9 million, respectively.*

24. CONTINGENCIES

Measurement inaccuracies occur from time to time with respect to the Utilities' metering facilities. Measurement adjustments for the Utilities are settled between the parties based on the requirements of the Electricity and Gas Inspections Act (Canada) and applicable regulations issued pursuant thereto. There is a risk of disallowance of the recovery of a measurement adjustment if controls and timely follow-up are found to be inadequate by the AUC.

The Corporation is party to a number of other disputes and lawsuits in the normal course of business. The Corporation believes that the ultimate liability arising from these matters will have no material impact on the consolidated financial statements.

In 2004, ATCO Gas and ATCO Electric transferred their retail energy supply businesses to Direct Energy Marketing Limited and one of its affiliates (collectively "DEML"), a subsidiary of Centrica plc. ATCO Gas and ATCO Electric continue to own and operate the natural gas and electricity distribution systems used to deliver energy.

Although ATCO Gas and ATCO Electric transferred to DEML certain retail functions, including the supply of natural gas and electricity to customers and billing and customer care functions, the legal obligations of ATCO Gas and ATCO Electric remain if DEML fails to perform. In certain events (including where DEML fails to supply natural gas and/or electricity and ATCO Gas and/or ATCO Electric are ordered by the AUC to do so), the functions will revert to ATCO Gas and/or ATCO Electric with no refund of the transfer proceeds to DEML by ATCO Gas and/or ATCO Electric.

Centrica plc, DEML's parent, has provided a $300 million guarantee, supported by a $235 million letter of credit in respect of DEML's obligations to ATCO Gas, ATCO Electric and ATCO I-Tek in respect of the ongoing relationships contemplated under the transaction agreements. However, there can be no assurance that the coverage under these agreements will be adequate to cover all of the costs that could arise in the event of a reversion of such functions.

Canadian Utilities Limited has provided a guarantee of ATCO Gas', ATCO Electric's and ATCO I-Tek's payment and indemnity obligations to DEML contemplated under the transaction agreements.

25. SEGMENTED INFORMATION

Description of segments

The **Utilities** segment includes the regulated distribution of natural gas by ATCO Gas, the regulated transmission of natural gas by ATCO Pipelines, and the regulated distribution and transmission of electricity by ATCO Electric and its subsidiaries, Northland Utilities (NWT), Northland Utilities (Yellowknife) and Yukon Electrical.

The **Energy** segment includes the non-regulated supply of electricity and cogeneration steam by ATCO Power, the regulated supply of electricity by Alberta Power (2000), and the non-regulated natural gas gathering, processing, storage, and natural gas liquids extraction by ATCO Midstream.

The **Corporate & Other** segment includes the Corporation's equity investment in ATCO Structures & Logistics, and the development, operation and support of information systems and technologies and the provision of billing services, payment processing, credit, collection and call centre services by ATCO I-Tek. The cash balances and commercial real estate owned by the Corporation in Alberta are also included in this segment.

Segmented results – Three months ended December 31

2010 2009 *(Unaudited)*	Utilities	Energy	Corporate & Other	Intersegment Eliminations	Consolidated
Revenues – external	**$405.3** $361.8	**$283.9** $294.7	**$20.1** $19.1	**$ -** $ -	**$709.3** $675.6
Revenues – intersegment[(1)]	**6.7** 6.1	**3.1** 1.4	**38.1** 33.6	**(47.9)** (41.1)	**-** -
Revenues	**$412.0** $367.9	**$287.0** $296.1	**$58.2** $52.7	**$(47.9)** $(41.1)	**$709.3** $675.6
Earnings attributable to Class A and Class B shares	**$ 71.5** $ 52.8	**$ 44.1** $ 72.5	**$13.3** $ 1.7	**$ (0.3)** $ 0.1	**$128.6** $127.1

(1) Intersegment revenues are recognized on the basis of prevailing market or regulated prices.

25. SEGMENTED INFORMATION (continued)

Segmented results – Year ended December 31

2010 2009	Utilities	Energy	Corporate & Other	Intersegment Eliminations	Consolidated
Revenues – external	**$1,451.7** $1,342.8	**$1,129.8** $1,021.9	**$ 75.7** $219.3	**$ -** $ -	**$2,657.2** $2,584.0
Revenues – intersegment [1]	**25.1** 24.7	**13.6** 9.5	**130.5** 125.6	**(169.2)** (159.8)	**-** -
Revenues	**1,476.8** 1,367.5	**1,143.4** 1,031.4	**206.2** 344.9	**(169.2)** (159.8)	**2,657.2** 2,584.0
Operating expenses	**819.6** 772.2	**764.9** 591.5	**140.1** 262.4	**(167.5)** (161.1)	**1,557.1** 1,465.0
Depreciation and amortization	**211.7** 192.4	**111.6** 116.8	**12.2** 20.5	**-** -	**335.5** 329.7
Interest expense	**176.8** 175.5	**59.4** 64.2	**188.4** 201.7	**(188.7)** (199.8)	**235.9** 241.6
Gain on ATCO Structures & Logistics Transaction	**-** -	**-** -	**-** (33.9)	**-** -	**-** (33.9)
Earnings from investment in ATCO Structures & Logistics	**-** -	**-** -	**(19.7)** (7.8)	**-** -	**(19.7)** (7.8)
Interest and other income	**(35.3)** (24.0)	**(1.0)** (15.4)	**(191.7)** (203.7)	**188.7** 199.8	**(39.3)** (43.3)
Earnings before income taxes	**304.0** 251.4	**208.5** 274.3	**76.9** 105.7	**(1.7)** 1.3	**587.7** 632.7
Income taxes	**38.6** 37.9	**56.4** 63.4	**14.6** 23.7	**(0.4)** 0.4	**109.2** 125.4
	265.4 213.5	**152.1** 210.9	**62.3** 82.0	**(1.3)** 0.9	**478.5** 507.3
Dividends on equity preferred shares	**20.8** 18.1	**1.4** 1.4	**21.3** 21.2	**-** -	**43.5** 40.7
Earnings attributable to Class A and Class B shares	**$ 244.6** $ 195.4	**$ 150.7** $ 209.5	**$ 41.0** $ 60.8	**$ (1.3)** $ 0.9	**$ 435.0** $ 466.6
Total assets	**$6,471.9** $5,921.9	**$2,254.9** $2,357.1	**$586.8** $791.0	**$ 101.7** $ 13.6	**$9,415.3** $9,083.6
Capital expenditures [2]	**$ 788.9** $ 776.1	**$ 67.1** $ 151.5	**$ 13.0** $ 18.5	**$ -** $ -	**$ 869.0** $ 946.1

(1) *Intersegment revenues are recognized on the basis of prevailing market or regulated prices.*
(2) *Includes purchases of property, plant and equipment and intangibles.*

25. SEGMENTED INFORMATION (continued)

Geographic segments

	Domestic		Foreign		Consolidated	
	2010	2009	**2010**	2009	**2010**	2009
Revenues	**$2,327.3**	$2,290.6	**$329.9**	$293.4	**$2,657.2**	$2,584.0
Property, plant and equipment and Intangibles	**$7,083.3**	$6,639.4	**$212.1**	$335.1	**$7,295.4**	$6,974.5

26. SUBSEQUENT EVENT

On January 1, 2011, ATCO Ltd., the Corporation's parent, transferred its wholly owned subsidiary, ATCO Resources, to ATCO Power, a wholly owned subsidiary of the Corporation. The fair value of the common shares of ATCO Resources, net of its existing debt obligations, was $82.5 million, as estimated by an independent financial advisor and supported by management.

ATCO Ltd. transferred its common shares of ATCO Resources to Canadian Utilities Limited in exchange for 1,059,658 Class A non-voting shares and 489,171 Class B common shares of Canadian Utilities, having a value of $82.5 million. This is a related party transaction between entities under common control and will be measured at the carrying amount.

CANADIAN UTILITIES LIMITED
Management's Discussion and Analysis (MD&A)
For the Year Ended December 31, 2010

This MD&A should be read in conjunction with the Corporation's unaudited consolidated financial statements for the three months ended December 31, 2010, and the audited consolidated financial statements for the year ended December 31, 2010. This MD&A is dated February 22, 2011. Additional information relating to the Corporation, including the Corporation's annual information form, is available on SEDAR at www.sedar.com.

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Glossary

Adjusted Earnings means earnings attributable to Class A and Class B Shares after adjustment for items that are not in the normal course of business or day-to-day operations. These items are usually of a non-recurring or one-time nature. Refer to Reconciliation of Earnings Attributable to Class A and Class B Shares and Adjusted Earnings section for a description of these items (non-GAAP item).

Adjusted Earnings per Class A and Class B Share is calculated by dividing Adjusted Earnings for a period by the weighted average number of Class A and Class B Shares outstanding during the period (non-GAAP item).

AESO means the Alberta Electric System Operator.

Alberta Power Pool means the market for electricity in Alberta operated by AESO.

ASL means ATCO Structures & Logistics Ltd.

ATCO Energy Solutions means ATCO Energy Solutions Ltd.

ATCO Frontec means ATCO Frontec Corp., the wholly owned subsidiary of Canadian Utilities Limited which amalgamated with ATCO Structures on July 1, 2009 to form ATCO Structures & Logistics Ltd.

ATCO Noise Management means ATCO Noise Management Ltd., the wholly owned subsidiary of ATCO that became a wholly owned subsidiary of ATCO Structures & Logistics Ltd. on July 1, 2009 and was subsequently amalgamated with ATCO Structures & Logistics Ltd. on January 1, 2010.

ATCO Structures means ATCO Structures Inc., the wholly owned subsidiary of ATCO Ltd. which amalgamated with ATCO Frontec on July 1, 2009 to form ATCO Structures & Logistics Ltd.

AUC means the Alberta Utilities Commission.

Availability is a measure of time, expressed as a percentage of continuous operation, that a generating unit is capable of producing electricity, regardless of whether the unit is actually generating electricity.

Class A Shares means Class A non-voting shares of the Corporation.

Class B Shares means Class B common shares of the Corporation.

Corporation means Canadian Utilities Limited and, unless the context otherwise requires, includes its subsidiaries.

Frac Spread means the premium or discount between the purchase price of natural gas and the selling price of extracted natural gas liquids on a heat content equivalent basis.

GAAP means Canadian generally accepted accounting principles.

GHG means any greenhouse gas which has the potential to retain heat in the atmosphere, including water vapour, carbon dioxide, methane, nitrous oxide and hydrofluorocarbons.

Gigajoule (GJ) means a unit of energy equal to approximately 948.2 thousand British thermal units.

IFRS means International Financial Reporting Standards.

Mark-to-market means assigning a value to a contract or financial instrument based on the current market prices for that contract or instrument or similar contracts or instruments.

Megawatt (MW) is a measure of electric power equal to 1,000,000 watts.

Megawatt hour (MWh) means a measure of electricity consumption equal to the use of 1,000,000 watts of power over a one-hour period.

NGL means natural gas liquids, such as ethane, propane, butane and pentanes plus, that are extracted from natural gas and sold as distinct products or as a mix.

Petajoule (PJ) means a unit of energy equal to approximately 948.2 billion British thermal units.

Placeholder means an AUC approved interim cost which has been included in utility customer rates pending an AUC review in a separate or future proceeding. This cost is subject to adjustment once the separate or future proceeding is completed and may result in refunds to or recoveries from customers.

PPA means Power Purchase Arrangements that became effective on January 1, 2001, as part of the process of restructuring the electric utility business in Alberta. The PPAs are legislatively mandated and approved by the AUC.

Propane Plus means propane, butane, pentane and other hydrocarbons other than methane and ethane.

Shrinkage gas means the natural gas which is used to replace, on a heat equivalent basis, the NGL extracted during NGL extraction operations.

Spark Spread means the difference between the selling price of electricity and the marginal cost of producing electricity from natural gas. In this MD&A, Spark Spreads are based on an approximate industry heat rate of 7.5 GJ per MWh.

U.K. means United Kingdom.

Company Overview

Alberta-based Canadian Utilities Limited, an ATCO Company, with more than 5,700 employees and assets of approximately $9 billion, delivers service excellence and innovative business solutions worldwide with leading companies engaged in Utilities (pipelines, natural gas and electricity transmission and distribution), Energy (power generation, natural gas gathering, processing, storage and liquid extraction) and Technologies (business systems solutions).

The consolidated financial statements include the accounts of Canadian Utilities Limited and all of its subsidiaries. The consolidated financial statements have been prepared in accordance with GAAP and the reporting currency is the Canadian dollar.

Internal Transfers of Subsidiaries

On January 1, 2011, ATCO, the Corporation's parent, transferred its wholly owned subsidiary, ATCO Resources, to ATCO Power, a wholly owned subsidiary of the Corporation. The fair value of the common shares of ATCO Resources, net of its existing debt obligations, was $82.5 million, as estimated by an independent financial advisor and supported by management.

ATCO transferred its common shares of ATCO Resources to the Corporation in exchange for 1,059,658 Class A Shares and 489,171 Class B Shares of the Corporation, having a value of $82.5 million. This is a related party transaction between entities under common control and will be measured at the carrying amount.

In addition, effective October 1, 2010, the ownership of Alberta Power (2000) Ltd. was transferred from CU Inc. to ATCO Power. Both CU Inc. and ATCO Power are wholly owned subsidiaries of the Corporation.

Segments

The Corporation operates in the following business segments:

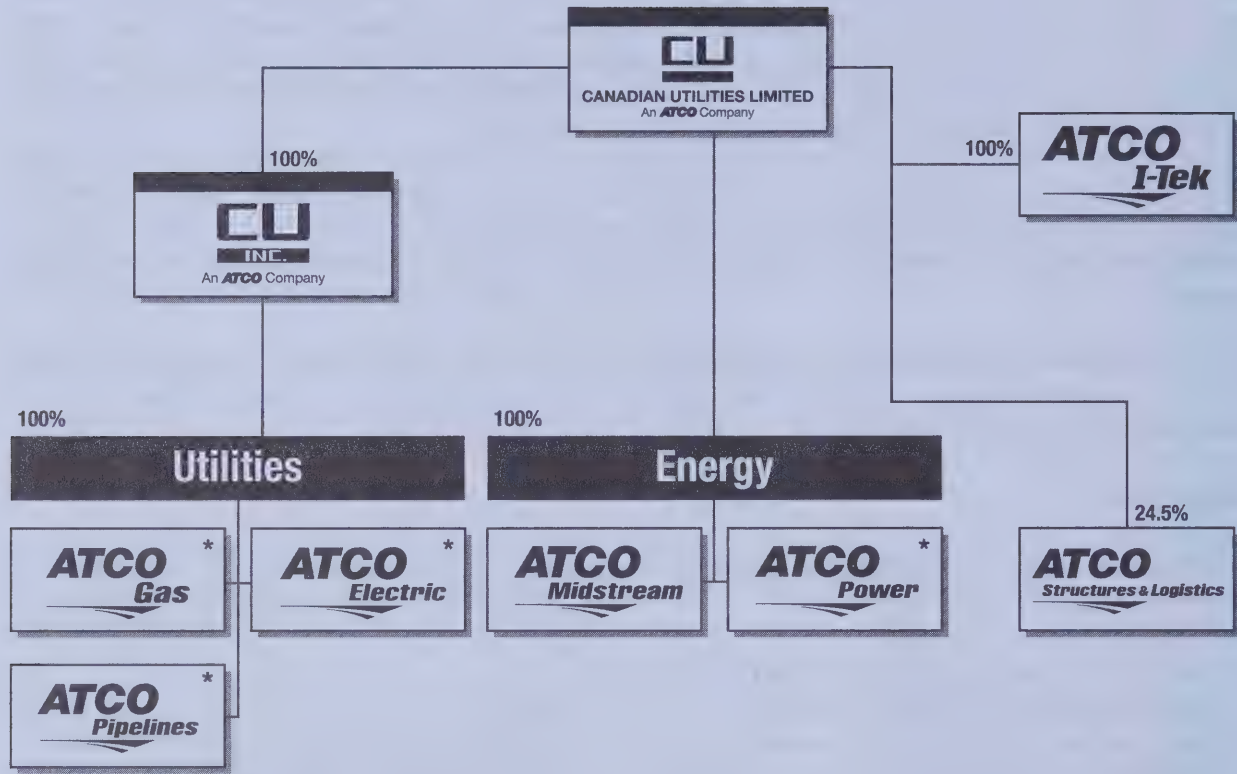
The **Utilities** Segment includes:
- the regulated distribution of natural gas by ATCO Gas;
- the regulated transmission of natural gas by ATCO Pipelines; and
- the regulated distribution and transmission of electric energy by ATCO Electric and its subsidiaries, Northland Utilities (NWT), Northland Utilities (Yellowknife) and Yukon Electrical.

The **Energy** Segment includes:
- the non-regulated supply of electricity and cogeneration steam by ATCO Power;
- the regulated supply of electricity by ATCO Power; and
- the non-regulated natural gas gathering, processing, storage and natural gas liquids extraction by ATCO Midstream.

The **Corporate & Other** Segment includes:
- the Corporation's 24.5% equity investment in ASL;
- the development, operation and support of information systems and technologies, and the provision of billing services, payment processing, credit, collection and call centre services by ATCO I-Tek; and
- short term investments and commercial real estate owned by the Corporation in Alberta.

Transactions between segments are eliminated in all reporting of the Corporation's consolidated financial information. For additional information about the Corporation's segments, refer to Note 25 to the consolidated financial statements.

Simplified Organizational Structure



* *Regulated operations include ATCO Gas, ATCO Electric, ATCO Pipelines and the Battle River and Sheerness generating plants of ATCO Power.*

ATCO AUSTRALIA INITIATIVE

On January 1, 2011, Steven J. Landry was appointed Managing Director & Chief Operating Officer of ATCO Australia Pty Ltd. Based in Perth, Western Australia, Mr. Landry will oversee the Corporation's energy, power generation and infrastructure business, including the three generating plants already in operation in that country. While the existing generating plants were reported in the Energy segment in 2010, effective January 1, 2011, the operations of ATCO Australia will be reported in a separate segment.

TRANSACTION TO COMBINE ATCO FRONTEC, ATCO STRUCTURES AND ATCO NOISE MANAGEMENT

On July 1, 2009, the Corporation and its parent, ATCO Ltd., finalized a transaction combining ATCO Frontec, a wholly owned subsidiary of the Corporation, with ATCO Structures and ATCO Noise Management, both wholly owned subsidiaries of ATCO Ltd. (ASL Transaction). As a result of this transaction, the Corporation and ATCO Ltd. have direct ownership interests of 24.5% and 75.5%, respectively, in the new company named ATCO Structures & Logistics Ltd. The ownership interests reflect the proportion of the respective valuations of the combined entities. The valuations were based on analysis prepared by independent financial advisors retained by the special committees of the Boards of Directors of the Corporation and ATCO Ltd.

This was a related party transaction by entities under common control and has been accounted for at the exchange amount by the Corporation; with an after tax gain for accounting purposes of $29.6 million recorded on closing.

For the six months ended June 30, 2009, the Corporation consolidated ATCO Frontec its wholly owned subsidiary. Therefore, ATCO Frontec's revenues, expenses, assets and liabilities were recognized on a line-by-line basis in the consolidated financial statements of the Corporation.

From July 1, 2009, the Corporation accounts for its 24.5% interest in ASL on the equity basis as it retains significant influence. This is reflected as a single line item called "Earnings from investment in ATCO Structures & Logistics" on the consolidated statement of earnings and a single line item called "Investment in ATCO Structures & Logistics" on the consolidated balance sheet.

The financial results of ATCO Frontec for the six months ended June 30, 2009, and the Corporation's 24.5% investment in ASL for the twelve months ended December 31, 2010, and the six months ended December 31, 2009, are reported in the Corporate & Other segment.

KARRATHA GENERATING PLANT

During 2010, the two unit 86 MW natural gas-fired simple cycle generating plant in Karratha, Western Australia (the "Karratha plant"), commenced commercial operations. Due to the nature of the contract governing the Karratha plant's revenues, GAAP requires that this agreement is accounted for as a finance lease (with the Corporation as the lessor). The total net investment in the finance lease is equal to the present value of the minimum lease payments receivable.

As this lease is considered a sales-type finance lease for accounting purposes, $129.8 million was recorded in revenues in 2010 to recognize the fair value of the lease receivable. These revenues were offset by $124.8 million in operation and maintenance expense associated with the construction costs of the two units which were removed from construction work in progress. This resulted in an increase in earnings of $3.5 million for the year ended December 31, 2010.

Forward-Looking Information

Certain statements contained in this MD&A constitute forward-looking information. Forward-looking information is often, but not always, identified by the use of words such as "anticipate", "plan", "estimate", "expect", "may", "will", "intend", "should", and similar expressions. Forward-looking information involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information. The Corporation believes that the expectations reflected in the forward-looking information are reasonable, but no assurance can be given that these expectations will prove to be correct and such forward-looking information should not be unduly relied upon.

Non-GAAP Measures

The Corporation uses the measures "Funds Generated by Operations", "Adjusted Earnings" and "Adjusted Earnings per Class A and Class B Share" in this MD&A. These measures do not have any standardized meaning under GAAP and might not be comparable to similar measures presented by other companies.

Funds Generated by Operations is defined as cash flow from operations before changes in non-cash working capital. In management's opinion, Funds Generated by Operations is a significant performance indicator of the Corporation's ability to generate cash during a period to fund its capital expenditures without regard to changes in non-cash working capital during the period.

Adjusted Earnings is defined as earnings attributable to Class A and Class B Shares after adjustment for items that are not in the normal course of business or day-to-day operations. These items are usually of a non-recurring or one-time nature. Management believes Adjusted Earnings allow for a more effective analysis of operating performance and trends. A reconciliation of Adjusted Earnings to earnings attributable to Class A and Class B Shares is presented in the Annual Results of Operations – Reconciliation of Earnings Attributable to Class A and Class B Shares and Adjusted Earnings section.

Controls and Procedures

DISCLOSURE CONTROLS AND PROCEDURES

As of December 31, 2010, the Corporation's management evaluated the effectiveness of the Corporation's disclosure controls and procedures, as defined under rules adopted by the Canadian Securities Administrators. This evaluation was performed under the supervision of, and with the participation of, the Chief Executive Officer (CEO) and the Chief Financial Officer (CFO).

Disclosure controls and procedures are controls and other procedures designed to provide reasonable assurance that information required to be disclosed in documents filed with securities regulatory authorities is recorded, processed, summarized and reported on a timely basis and is accumulated and communicated to the Corporation's management, including the CEO and the CFO, as appropriate, to allow timely decisions regarding required disclosure.

The Corporation's management, inclusive of the CEO and the CFO, does not expect that the Corporation's disclosure controls and procedures will prevent or detect all errors. The inherent limitations in all control systems are such that they can provide only reasonable, not absolute, assurance that all control issues and instances of error, if any, within the Corporation have been detected.

Based on this evaluation, the CEO and the CFO have concluded that the Corporation's disclosure controls and procedures were effective at December 31, 2010.

INTERNAL CONTROL OVER FINANCIAL REPORTING

As of December 31, 2010, the Corporation's management evaluated the effectiveness of the Corporation's internal control over financial reporting, as defined under rules adopted by the Canadian Securities Administrators. This evaluation was performed under the supervision of, and with the participation of, the CEO and the CFO.

The Corporation's internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP.

Internal control over financial reporting, no matter how well designed, has inherent limitations. Therefore, internal control over financial reporting can provide only reasonable assurance with respect to financial statement preparation and may not prevent or detect all misstatements.

Based on this evaluation, the CEO and the CFO have concluded that the Corporation's internal control over financial reporting was effective at December 31, 2010.

There was no change in the Corporation's internal control over financial reporting that occurred during the period beginning on October 1, 2010, and ended on December 31, 2010, that has materially affected, or is reasonably likely to materially affect, the Corporation's internal control over financial reporting.

Annual Results of Operations

SELECTED INFORMATION

($ millions, except per share data, outstanding shares and return on equity) [1] [2]	For the Year Ended December 31 2010	2009	2008
Revenues	**2,657.2**	2,584.0	2,778.9
Earnings attributable to Class A and Class B Shares	**435.0**	466.6	414.5
Adjusted Earnings [3]	**440.9**	427.6	403.2
Total assets	**9,415.3**	9,083.6	7,860.0
Long term debt	**3,060.3**	3,102.3	2,844.3
Non-recourse long term debt	**302.8**	354.8	412.4
Equity preferred shares	**860.0**	785.0	625.0
Class A and Class B Share owners' equity	**3,275.2**	3,046.1	2,748.5
Return on equity (%)	**13.8**	16.1	15.7
Cash flow from operations	**764.3**	738.3	783.7
Funds Generated by Operations	**738.2**	793.4	796.5
Capital expenditures	**869.0**	946.1	1,010.9
Earnings per Class A and Class B Share ($)	**3.46**	3.71	3.30
Diluted earnings per Class A and Class B Share ($)	**3.45**	3.71	3.29
Adjusted Earnings per Class A and Class B Share ($) [3]	**3.50**	3.40	3.21
Cash dividends declared per share ($):			
Series Second Preferred Shares:			
Series O [4]	**1.09**	1.09	1.09
Series T [4]	**1.09**	1.09	1.09
Series U [4]	**1.09**	1.09	1.09
Series V [5]	**1.18**	1.18	1.18
Series W	**1.45**	1.45	1.45
Series X	**1.50**	1.50	1.50
Class A and Class B Share	**1.51**	1.41	1.33
Equity per Class A and Class B Share ($)	**26.01**	24.20	21.90
Class A and Class B Shares outstanding, year end (thousands)	**125,930**	125,860	125,510
Weighted average Class A and Class B Shares outstanding (thousands):			
Basic	**125,851**	125,637	125,408
Diluted	**125,971**	125,774	125,784

Notes:

(1) *There were no discontinued operations or extraordinary items during these periods.*

(2) *The above data (other than Adjusted Earnings, Adjusted Earnings per Class A and Class B Share, Funds Generated by Operations, Return on equity and Equity per Class A and Class B Share) has been extracted from the financial statements.*

(3) *Refer to Significant Non-Operating Financial Items section for a description of the adjustments made to earnings attributable to Class A and Class B Shares to obtain Adjusted Earnings.*

(4) *The dividend rate was reset to $1.09 (from 5.05% to 4.35%) for the period between December 2, 2006, and December 2, 2011.*

(5) *The dividend rate was reset to $1.18 (from 5.25% to 4.70%) for the period between October 3, 2007, and October 3, 2012.*

RECONCILIATION OF EARNINGS ATTRIBUTABLE TO CLASS A AND CLASS B SHARES AND ADJUSTED EARNINGS

Adjusted Earnings are referred to in various sections of this MD&A. The following table reconciles Adjusted Earnings, which are earnings attributable to Class A and Class B Shares after adjustments for items that are not in the normal course of business or day-to-day operations. These items are usually of a non-recurring or one-time nature. A description of each adjustment is provided in the Significant Non-Operating Financial Items section.

	For the Year Ended December 31	
($ millions)	**2010**	2009
Earnings attributable to Class A and Class B Shares	**435.0**	466.6
Mark-to-Market Adjustment (1)	**5.9**	7.4
H.R. Milner Income Tax Reassessment (2)	-	(16.8)
Gain on transaction to combine ATCO Frontec, ATCO Structures and ATCO Noise Management (3)	-	(29.6)
Adjusted Earnings	**440.9**	427.6

SIGNIFICANT NON-OPERATING FINANCIAL ITEMS

Consolidated and segmented financial results include the following significant non-operating financial items.

(1) Natural Gas Purchase Contracts and Associated Power Generation Revenue Contract Liability (Mark-to-Market Adjustment)

ATCO Power has long term contracts for the supply of natural gas for certain of its power generation projects. Under the terms of certain of these contracts, the volume of natural gas that the Corporation is entitled to take is in excess of the natural gas required to generate power. As the excess volume of natural gas can be sold, the Corporation is required to designate these entire contracts as derivative instruments. The Corporation recognizes a non-current derivative asset and a non-current derivative liability and records mark-to-market adjustments through earnings as the fair values of these contracts change with changes in future natural gas prices. These natural gas purchase contracts expire in November 2014.

As all but the excess volume of natural gas is committed to the Corporation's power generation obligations, the Corporation does not recognize the entire fair values of these natural gas purchase contracts in its revenues. Consequently, the Corporation has recognized a provision for a power generation revenue contract and records adjustments to the power generation revenue contract liability concurrently with the mark-to-market adjustments for the natural gas purchase contract derivative asset. This power generation revenue contract liability is included in deferred credits in the consolidated balance sheet.

The mark-to-market adjustment for the derivative asset and derivative liability and the corresponding adjustment for the associated power generation revenue contract liability decreased earnings by $1.9 million, for the three months ended December 31, 2010 (2009 – decrease of $2.0 million) and decreased earnings by $5.9 million, for the year ended December 31, 2010 (2009 – decrease of $7.4 million). At December 31, 2010, the natural gas purchase contract derivative asset was $1.5 million (2009 – $26.0 million), the natural gas purchase contract derivative liability was $2.2 million (2009 - nil), and

the power generation revenue contract liability was $1.5 million (2009 – $20.4 million). The value of the natural gas purchase contracts derivative asset has declined by $24.5 million and the power generation revenue contract liability has declined by $18.9 million compared to 2009 due mainly to the decline in the forward price of natural gas.

(2) H.R. Milner Income Tax Reassessment

In 2006, Canada Revenue Agency (CRA) issued an income tax reassessment for Alberta Power (2000)'s 2001 taxation year which treated the proceeds received from the sale of the H.R. Milner generating plant to the Balancing Pool as income rather than as a sale of an asset. The Corporation disagreed with CRA's position and appealed the reassessment to the Tax Court of Canada. Due to the uncertainty as to whether the reassessment would ultimately be resolved in the Corporation's favour, the Corporation made a $28.8 million payment and reduced earnings by $12.4 million in 2006.

On August 21, 2009, Alberta Power (2000) received a judgment from the Tax Court of Canada ordering CRA to reverse its 2006 reassessment of Alberta Power (2000)'s 2001 tax return. On September 30, 2009, the appeal period for the judgment elapsed without an appeal from CRA.

The impact of the judgment was a $13.7 million recovery of income tax and related interest expense reassessed by CRA in 2006. In addition, Alberta Power (2000) received interest income of approximately $3.1 million earned on such amounts paid to CRA. These adjustments resulted in a $16.8 million increase in earnings which was recorded in the third quarter of 2009. In total, Alberta Power (2000) received refunds of approximately $28.0 million, including interest, and net of consequential adjustments to other taxation years arising from the judgment.

(3) Gain on Transaction to Combine ATCO Frontec, ATCO Structures and ATCO Noise Management

On July 1, 2009, the Corporation finalized the ASL Transaction which resulted in an after tax gain of $29.6 million (refer to Company Overview – Transaction To Combine ATCO Frontec, ATCO Structures and ATCO Noise Management section).

CONSOLIDATED REVENUES AND ADJUSTED EARNINGS

Revenues in 2010 **increased** by $73.2 million (3%) over 2009. Of this increase, $129.8 million related to the fair value of the lease for the Karratha plant, which is offset by $124.8 million of operation and maintenance costs. In addition, revenues increased due to a $109.3 million (8%) increase in the Utilities Segment due to increased rate base in ATCO Electric and an AUC decision received on the Carbon Compliance Application, partially offset by Carbon decisions recorded in 2009 (Carbon Decisions) in ATCO Gas and the deferred gas account decision by the Alberta Court of Appeal (Deferred Gas Account Decision) in ATCO Gas (refer to Segmented Information – Utilities section). These increases were partially offset by a $138.7 million (40%) decrease in the Corporate & Other Segment due to the impact of the ATCO Structures & Logistics Transaction.

Adjusted earnings in 2010 were $440.9 million, an **increase** of $13.3 million (3%) over 2009. This increase was primarily attributable to a $49.2 million (25%) increase in the Utilities Segment due to the Carbon Decisions in ATCO Gas and increased rate base in ATCO Electric, ATCO Gas and ATCO Pipelines (the Utilities), partially offset by the Deferred Gas Account Decision in ATCO Gas. These increases were partially offset by a $43.5 million (22%) decrease in the Energy Segment mainly due to lower summer/winter natural gas price differentials for storage (Storage Price Differentials) in ATCO Midstream.

Interest and other income in 2010 **decreased** by $4.0 million to $39.3 million compared to 2009 mainly due to interest income recognized in 2009 on the H.R. Milner Income Tax Reassessment in ATCO Power, partially offset by interest income recognized on ATCO Gas' Carbon Compliance decision (refer to Segmented Information – Utilities section).

CONSOLIDATED EXPENSES

($ millions)	For the Year Ended December 31 **2010**	2009	Change to 2010 (2010-2009)
Operating expenses:			
Natural gas supply	**88.7**	23.2	282%
Purchased power	**54.2**	54.1	0%
Operation and maintenance	**974.8**	965.5	1%
Selling and administrative	**266.7**	258.7	3%
Franchise fees	**172.7**	163.5	6%
	1,557.1	1,465.0	6%
Depreciation and amortization	**335.5**	329.7	2%
Interest	**235.9**	241.6	(2%)
Income taxes	**109.2**	125.4	(13%)
Dividends on equity preferred shares	**43.5**	40.7	7%

Operating expenses in 2010 **increased** by $92.1 million (6%) compared to 2009. Natural gas supply expense increased due to higher flow through natural gas purchases in ATCO Midstream. Operation and maintenance expenses were higher due to the lease accounting treatment on the completion of the Karratha plant, partially offset by the impact of the ATCO Structures & Logistics Transaction.

In 2010, **depreciation and amortization expenses increased** by $5.8 million (2%) over 2009, primarily due to capital additions in 2009 and 2010 in the Utilities, partially offset by the impact of the ATCO Structures & Logistics Transaction.

Interest expense in 2010 **decreased** by $5.7 million (2%) compared to 2009, primarily due to the repayment of non-recourse long term debt in ATCO Power and the redemption of $125.0 million of CU Inc. 11.40% debentures on August 15, 2010. These debentures were not refinanced until the November 18, 2010 issuance of $125.0 million of CU Inc. 4.947% debentures. This decrease was partially offset by higher interest on long term debt related to the Karratha plant and the impact of the Deferred Gas Account Decision in ATCO Gas.

In 2010, **income taxes decreased** by $16.2 million (13%) compared to 2009, primarily due to a decrease in earnings before income taxes and lower income tax rates.

Dividends on equity preferred shares in 2010 **increased** by $2.8 million (7%) over 2009 as a result of the issue by CU Inc. of $160.0 million of 6.70% Cumulative Redeemable Preferred Shares Series 2 on March 27, 2009, and $75.0 million of 3.80% Cumulative Redeemable Preferred Shares Series 4 on December 2, 2010.

SEGMENTED INFORMATION

($ millions)	Utilities	Energy	Corporate & Other	Intersegment Eliminations	Total
	For the Year Ended December 31				
2010					
Revenues	**1,476.8**	**1,143.4**	**206.2**	**(169.2)**	**2,657.2**
Earnings attributable to Class A and Class B Shares	**244.6**	**150.7**	**41.0**	**(1.3)**	**435.0**
Mark-to-Market Adjustment (1)	**-**	**5.9**	**-**	**-**	**5.9**
Adjusted Earnings	**244.6**	**156.6**	**41.0**	**(1.3)**	**440.9**
Capital expenditures	**788.9**	**67.1**	**13.0**	**-**	**869.0**
Operating expenses	**819.6**	**764.9**	**140.1**	**(167.5)**	**1,557.1**
2009					
Revenues	1,367.5	1,031.4	344.9	(159.8)	2,584.0
Earnings attributable to Class A and Class B Shares	195.4	209.5	60.8	0.9	466.6
Mark-to-Market Adjustment (1)	-	7.4	-	-	7.4
H.R. Milner Income Tax Reassessment (2)	-	(16.8)	-	-	(16.8)
Gain on transaction to combine ATCO Frontec, ATCO Structures and ATCO Noise Management (3)	-	-	(29.6)	-	(29.6)
Adjusted Earnings	195.4	200.1	31.2	0.9	427.6
Capital expenditures	776.1	151.5	18.5	-	946.1
Operating expenses	772.2	591.5	262.4	(161.1)	1,465.0

Notes:
(1) (2) (3) Refer to Significant Non-Operating Financial Items section for a description of the adjustments.

Utilities

The Utilities are regulated primarily by the AUC, which administers acts and regulations covering such matters as rates, financing, accounting and service area. The Utilities are subject to a cost of service regulatory mechanism under which the AUC establishes the revenues required (i) to recover the forecast operating costs, including depreciation and amortization and income taxes, of providing the regulated service, and (ii) to provide a fair return on utility investment, or rate base. Rate base for each utility is the aggregate of the AUC approved investment in property, plant and equipment and intangible assets, less accumulated depreciation and amortization, reserves for future removal and site restoration, and unamortized contributions by utility customers for extensions to plant, plus an allowance for working capital. The Utilities earn a return on rate base intended to meet the cost of the debt and preferred share components of rate base and to provide share owners with a fair return on the common equity component of rate base. The determination of a fair return to the common shareholders involves an assessment by the regulator of many factors, including returns on alternative investment opportunities of comparable risk and the level of return which will enable a utility to attract the necessary capital to fund its operations and to maintain financial integrity.

Utilities **revenues** in 2010 were $1,476.8 million, an **increase** of $109.3 million (8%) over 2009. This increase in revenues was primarily attributable to increased rate base in ATCO Electric and the Carbon Decisions in ATCO Gas, partially offset by the Deferred Gas Account Decision in ATCO Gas.

In 2010, **Adjusted Earnings** were $244.6 million, an **increase** of $49.2 million (25%) over 2009. The primary reasons for higher Adjusted Earnings were the Carbon Decisions in ATCO Gas and increased rate base in the Utilities, partially offset by the Deferred Gas Account Decision in ATCO Gas.

Regulatory Developments

AUC Initiative to Reform Rate Regulation

On February 26, 2010, the AUC advised that it was beginning an initiative to reform utility rate regulation in Alberta. The intent of this initiative is to move to a form of rate regulation referred to as "performance based regulation" in which prevailing rates are adjusted annually by a formula that recognizes inflation and productivity improvements. The rate regulation initiative will begin with the reform of rate regulation for electricity and natural gas distribution services. The reform of rate regulation for electricity and natural gas transmission is excluded from this initiative at this time.

The AUC has advised that the target date for the implementation of performance based regulation for ATCO Gas and ATCO Electric will be January 1, 2013, based on applications to be filed in the second quarter of 2011. The impact of this initiative on ATCO Gas' and ATCO Electric's distribution operations cannot be determined at this time.

Generic Cost of Capital

On November 12, 2009, the AUC issued its decision on the 2009 Generic Cost of Capital proceeding. In this decision, the AUC set the 2009 and 2010 generic return on equity (ROE) at 9.0% for all Alberta utilities which it regulates. The AUC has maintained the concept of a single generic ROE for all utilities, with differences in utility or sector specific risk to be recognized through the adjustments of individual common equity ratios. The AUC determined the common equity ratio to be 36% for ATCO Electric's transmission operations, 39% for both ATCO Electric's distribution operations and ATCO Gas' operations and 45% for ATCO Pipelines' operations.

As part of the same decision, the AUC also set the 2011 generic return on equity at 9.0% on an interim basis subject to change following a subsequent generic proceeding. On December 16, 2010, the AUC initiated a 2011 Generic Cost of Capital proceeding, the scope of which includes, among other things, a full review of cost of capital matters including capital structure and the ROE for 2011. It will also include consideration of whether a formula approach to ROE can be reinstated for 2012. In the absence of a formula approach to ROE, the AUC will then consider how the ROE will be set for 2012. The scope also includes consideration of a management fee on customer contributed assets and how such a fee would be accounted for. The proceeding is scheduled to be completed in the third quarter of 2011 and a decision is expected in the fourth quarter of 2011.

Pension Hearing

In July 2009, the Utilities submitted an application to the AUC requesting recovery of the expected 2010 contributions to the Canadian Utilities pension plan. Prior to 2010, there had been no required contributions since 1996. The Utilities also requested the establishment of deferral accounts due to projected funding requirements and the potential for fluctuations in pension asset values and resulting funding requirements. A hearing was held in January 2010 and an AUC decision was issued on April 30,

2010, approving the requested funding and establishing deferral accounts for funding fluctuations beyond the control of the Utilities. This decision did not result in a material change in the Utilities' earnings.

On December 15, 2010, the Utilities submitted an application supporting the pension methodology, specifically the determination of the cost of living allowance provision, used in the determination of pension costs included in the 2011 and future years' revenue requirements of the Utilities. The AUC expanded the scope of the application so that it will also be the basis to determine the 2011/2012 pension cost recovery for the Utilities. The application is as a result of a directive issued by the AUC in the pension decision issued on April 30, 2010. A decision is expected in the fourth quarter of 2011.

Benchmarking

The Utilities purchase information technology services from ATCO I-Tek. ATCO Electric and ATCO Gas also purchase customer care and billing services from ATCO I-Tek. The recovery of these costs in customer rates is subject to AUC approval. Since 2003, the costs have been approved on a Placeholder basis. An AUC decision was issued on March 8, 2010, which addressed the 2003-2007 Placeholder amounts for the Utilities. The AUC decision approved the adjustments to the Placeholder amounts as filed based on fair market value resulting in no material changes to earnings.

For the 2008 and 2009 period, a separate regulatory process has been established to approve rates for information technology and customer care and billing services provided by ATCO I-Tek that can be included in customer rates. The proceeding is scheduled to be completed in the first quarter of 2011 and a decision is expected in the second quarter of 2011.

A further regulatory process to deal with rates for information technology and customer care and billing services provided by ATCO I-Tek for 2010 and beyond has been established and the AUC is expected to set a schedule for this regulatory process after the completion of the 2008 – 2009 process.

In addition to the rates, this process includes the review of three options for the future provision of information technology and customer care and billing services. The options are (i) the repatriation of these services back into the Utilities; (ii) moving to a third party service provider; or (iii) renewing with ATCO I-Tek, the current service provider. On December 11, 2009, the AUC issued a decision approving the implementation of the new Master Service Agreements (excluding the rates therein) with ATCO I-Tek for information technology and customer care and billing services effective January 1, 2010, for an interim period, the term of which will be determined in the upcoming regulatory process.

Utility Asset Disposition Rate Review Proceeding

In March 2008, the AUC initiated a proceeding to consider the potential rate related implications for Alberta utilities of the Supreme Court of Canada's 2006 Calgary Stores Block decision (Stores Block Decision). The Calgary Stores Block matter involved the disposition by ATCO Gas of its Calgary Stores Block facility and adjacent property in downtown Calgary. The Supreme Court held that utility shareholders were entitled to receive all proceeds resulting from the sale.

The AUC has indicated that the Stores Block Decision may have various implications with respect to regulation of Alberta utility companies (including the potential impact of the Carbon Natural Gas Storage Facility decision discussed below). The AUC has stated that it would like to develop a comprehensive understanding of these potential implications through this proceeding and then apply this understanding in a consistent manner in future decisions. At the conclusion of this proceeding, the AUC will issue a decision reflecting its conclusions with respect to the interpretation and application of the guidance provided by the courts and the resulting implications to be used in future proceedings. On November 28, 2008, the AUC suspended the utility asset disposition rate review proceeding until further notice to allow

for various related matters currently before the courts to be addressed. As of December 31, 2010, this proceeding remains suspended.

ATCO Electric

2011 and 2012 General Tariff Application

In May 2010, ATCO Electric filed a general tariff application with the AUC for 2011 and 2012 requesting, among other things, increased revenues to recover increased financing, depreciation, and operating costs associated with increased rate base in Alberta. The application also requested that construction work in progress for projects that are directly assigned from the AESO be included in rate base. Further, ATCO Electric is also seeking recovery of Federal future income taxes in customer rates for its transmission operations. These requests would not impact earnings but would improve cash flow during the construction of the major transmission projects currently being undertaken. A decision is expected in the second quarter of 2011.

2009 and 2010 General Tariff Application

On July 2, 2009, the AUC issued a decision on ATCO Electric's 2009 and 2010 general tariff application approving, among other things, increased revenues to recover increased financing, depreciation and operating costs associated with increased rate base in Alberta. The impact of increased rate base for the year ended December 31, 2010, increased ATCO Electric's revenues and earnings by approximately $75 million and $13 million, respectively, compared to 2009.

Transmission Infrastructure Projects

Northwest Alberta Transmission Projects

In August 2006, the AUC approved the AESO application for increased transmission infrastructure in northwest Alberta. The work includes four distinct transmission line projects and will result in approximately 700 kilometres of new transmission lines to be constructed by 2012.

All four transmission line projects have been assigned to ATCO Electric by the AESO and final approval has been received from the AUC for these projects with an estimated cost of $415.0 million and completion estimated by the end of the second quarter of 2012. ATCO Electric has completed construction of two of the transmission lines totaling 480 kilometres and is currently constructing the two other transmission lines totaling approximately 220 kilometres.

In addition to the four transmission line projects, there are several additional infrastructure projects in northwest Alberta with an estimated cost of approximately $75 million which are anticipated to be complete by the end of 2012. ATCO Electric estimates the total cost of the northwest Alberta projects to be approximately $490 million, $385 million of which has been incurred and included in the financial statements for the year ended December 31, 2010.

AESO Long-Term Transmission System Plan

In June 2009, the AESO released its long-term transmission system plan. This plan identifies $8.1 billion of critical transmission infrastructure projects that are needed between 2010 and 2017 to meet current and future electricity needs in Alberta and a further $6.4 billion in projects that are at a less advanced stage of planning. The Alberta government passed amendments to the Alberta Utilities Commission Act, the Electric Utilities Act, and the Hydro and Electric Energy Act to expedite the determination of these

critical transmission infrastructure projects. The amendments to the Electric Utilities Act allow the government to directly assign projects, utilize service territory assignments or put future critical transmission infrastructure projects out for competitive bid.

Pursuant to the amended legislation, the AESO is in the process of developing a recommended model for the competitive procurement process for critical transmission infrastructure. Competitive procurement refers to the provision of specific transmission infrastructure via a process that enables all deemed qualified bidders to compete in a fair, transparent and open environment for the right to build, own and operate or transfer the identified transmission infrastructure to an existing Transmission Facility Owner. The AESO expects to issue a draft recommended process by the end of the first quarter of 2011. The AESO will then develop a competitive procurement process document to file with the AUC, currently anticipated for the third quarter of 2011, for its approval.

500kV High Voltage Direct Current ("HVDC") Project

In 2009, ATCO Electric was authorized by the Alberta Minister of Energy to prepare a facility application to build and operate a new 500kV HVDC transmission line along a corridor on the east side of the province between Edmonton and Calgary. Following approval of the facility application by the AUC, ATCO Electric will construct and operate the new line. In December 2010, ATCO Electric filed its proposal for the project with the AESO at an estimated cost, excluding capitalized interest during construction, of $1.6 billion with an in-service date of December 31, 2013. In February 2011, the AESO revised the required in-service date to mid to late 2014 and directed ATCO Electric to review and update its original proposal for the project incorporating the new in-service date and any revisions to the estimated cost. Once ATCO Electric files and the AESO accepts the revised project proposal, ATCO Electric expects to complete and file the facility application with the AUC in the first quarter of 2011 seeking final approval to construct and operate the facility. Final approval is not anticipated until late 2011. Approval of the facility application is required before construction commences. It is anticipated that the majority of the project costs will be incurred in 2012 through 2014.

Hanna Region Transmission Development ("HRTD") Project

On April 29, 2010, the AUC approved the need for major transmission reinforcement in the Hanna area located in the southeast region of the province. ATCO Electric's share of the Hanna Region Transmission Development, or "HRTD", is comprised of six distinct developments comprising approximately 375 kilometres of transmission line projects, the construction of seven new substations and modifications and expansions to a further 13 existing substations. The in-service dates for the majority of these six developments are anticipated to be in late 2012 with an estimated cost for the HRTD of approximately $800 million. ATCO Electric expects to file the remainder of the facility applications with the AUC by the end of the first quarter of 2011, final approvals for which are not anticipated until the fourth quarter of 2011. It is anticipated that the majority of these costs will be incurred in 2011 and 2012.

In addition to the increased transmission infrastructure in northwest Alberta and the HVDC and HRTD projects, ATCO Electric anticipates that 500 – 1,000 kilometres of transmission line projects will be required in its service area over the next five years. The increase in kilometres is mainly as a result of projects identified in the AESO's long term transmission plan.

ATCO Gas

2011 and 2012 General Rate Application

In December 2010, ATCO Gas filed a general rate application with the AUC for 2011 and 2012 requesting, among other things, increased revenues to recover increased financing, depreciation, and operating costs associated with increased rate base in Alberta. A decision is expected in the fourth quarter of 2011. ATCO Gas also filed an application requesting interim adjustable rates pending the AUC's decision on the general rate application. A decision on the interim adjustable rates application is expected in the first quarter of 2011.

Carbon Natural Gas Storage Facility

ATCO Gas owns a 43.5 petajoule natural gas storage facility located at Carbon, Alberta (Carbon Facility). Since April 1, 2005, ATCO Gas has leased the entire storage capacity of the Carbon Facility to ATCO Midstream. Due to the deregulation of the natural gas market, ATCO Gas notified the AUC that the Carbon Facility was no longer required for the provision of utility service as of April 1, 2005. As a result of numerous regulatory and legal proceedings, ATCO Gas has received approval from the AUC to remove the Carbon Facility from regulation. On December 16, 2009, a Review and Variance decision issued by the AUC confirmed the effective date of removing the Carbon Facility from regulation to be April 1, 2005.

Through its Carbon Compliance application, ATCO Gas sought to recover total revenues from customers of $45.5 million, excluding interest, which would increase ATCO Gas' earnings by a total of $32.7 million. On October 19, 2010, the AUC released the Carbon Compliance decision, approving a recovery from customers of $43.7 million plus interest in the amount of $5.9 million to September 30, 2010. Through numerous regulatory processes, ATCO Gas has previously recorded revenues and earnings of $13.8 million and $9.9 million, respectively, in 2009. Additionally, on April 20, 2010, ATCO Gas received a decision from the AUC approving, on an interim adjustable basis, the implementation of Carbon recovery riders resulting in an increase in ATCO Gas' revenues and earnings of $15.7 million and $11.3 million, respectively. As a result, in the third quarter of 2010, ATCO Gas recognized the remaining amounts pertaining to the Carbon Compliance application and related decision issued by the AUC resulting in an increase in ATCO Gas' revenues, interest income and earnings of $14.2 million, $5.9 million, and $14.5 million, respectively.

ATCO Gas filed an application with the AUC on December 1, 2010, to approve the internal transfer of the Carbon facility from ATCO Gas to ATCO Midstream. The transaction is subject to the completion of documentation and receipt of all necessary approvals, including regulatory approval in a form satisfactory to the Board of Directors of Canadian Utilities. The transaction is expected to be completed in the second quarter of 2011.

Deferred Gas Account

ATCO Gas filed an application with the AUC to address, among other things, corrections required to historical transportation imbalances (the process whereby third party natural gas supplies are reconciled to amounts actually shipped in a corporation's pipelines) that have impacted ATCO Gas' deferred gas account. In April 2005, the AUC issued a decision resulting in a 15% decrease in the transportation imbalance adjustments sought by ATCO Gas. The decision resulted in ATCO Gas recovering $9.2 million in natural gas supply costs from customers.

The City of Calgary's appeal with respect to this decision was heard by the Alberta Court of Appeal on January 13, 2010. On April 23, 2010, the Alberta Court of Appeal issued a decision allowing the appeal and vacating orders under appeal and returned the matter to the AUC for consideration. The AUC completed a process to address the Alberta Court of Appeal decision and on October 15, 2010, issued a decision requiring ATCO Gas to refund to customers approximately 85% of the transportation imbalance adjustment amounts in question resulting in a refund of approximately $9.7 million, including interest of $1.7 million, and a decrease in ATCO Gas' 2010 earnings of $7.1 million.

2005, 2006, and 2009 General Rate Application

In May 2006, the City of Calgary filed a review and variance application with the AUC, alleging that the AUC made errors in ATCO Gas' 2005-2007 general rate application decision related to the calculation of working capital needed by ATCO Gas to operate the Carbon Facility. The AUC issued a decision on January 17, 2007, denying the City of Calgary's application. On February 15, 2007, the City of Calgary filed for a Leave to Appeal this decision with the Alberta Court of Appeal. On June 19, 2007, the appeal was heard with the Court granting the City of Calgary leave to appeal on August 3, 2007. A hearing was held on March 11, 2010, and a decision dismissing the appeal was issued by the Alberta Court of Appeal on March 24, 2010.

ATCO Pipelines

Alberta System Integration

In 2008, ATCO Pipelines and NOVA Gas Transmission Ltd. (NOVA) announced a proposed agreement to provide natural gas transmission service to their customers. The proposal will allow ATCO Pipelines and NOVA to utilize their physical assets under a single rates and services structure with a single commercial interface for Alberta customers. Each company would separately manage assets within distinct operating territories within Alberta. This proposal, if approved by the AUC, is expected to end duplicate tolling and operational activities and result in more efficient regulatory processes.

In 2009, ATCO Pipelines filed an application with the AUC for the integration of ATCO Pipelines' and NOVA's gas transmission systems in Alberta (Integration Application), and filed a second application with the AUC to approve its 2010, 2011 and 2012 negotiated settlement, which was a condition precedent of the Integration Application.

The AUC issued a decision on May 27, 2010, approving integration and the 2010, 2011 and 2012 negotiated settlement but requested ATCO Pipelines to submit subsequent applications to address the specific details on: (i) the transition of ATCO Pipelines' customers to NOVA, and (ii) the asset swap between ATCO Pipelines and NOVA in order to establish operating areas. ATCO Pipelines has submitted an application to the AUC to address the transition of customers and a decision is expected in the second quarter of 2011. An application to address the asset swap will be submitted to the AUC in the first quarter of 2011.

Other Matters

The Corporation has a number of other less significant regulatory filings and regulatory hearing submissions before the AUC for which decisions have not been received. The outcome of these matters cannot be determined at this time.

Energy

Energy **revenues** in 2010 **increased** by $112.0 million (11%) over the same period in 2009. This increase was primarily attributable to the lease accounting treatment on the completion and commencement of operation of the Karratha plant in Australia, higher merchant performance in ATCO Power's Alberta generating plants due to higher prices in the Alberta electricity market and higher flow through natural gas sales and NGL prices in ATCO Midstream. These increases in revenues were partially offset by decreased Storage Price Differentials in ATCO Midstream, decreased revenues at ATCO Power's Barking generating plant due to the expiry of the revenue contract on September 30, 2010 (refer to Business Risks – Non-regulated Operations section) and lower exchange rates on conversion of U.K. revenues into Canadian dollars.

Adjusted Earnings were $156.6 million, a **decrease** of $43.5 million (22%) compared to 2009. This decrease was primarily attributable to lower Storage Price Differentials in ATCO Midstream, the expiry of the Barking revenue contract on September 30, 2010, and lower exchange rates on conversion of U.K. earnings into Canadian dollars in ATCO Power. These decreases were partially offset by higher Frac Spreads in ATCO Midstream, higher merchant performance in ATCO Power's Alberta generating plants due to higher Spark Spreads in the Alberta electricity market, and earnings attributable to the lease accounting treatment on the completion and commencement of operations of the Karratha plant.

Power Generation

Availability of the generating plants by geographic region is set forth below:

	For the Year Ended December 31		
	2010	2009	Change to 2010 (2010-2009)
Independent Power Plants(1):			
Canada	**96.0%**	96.3%	(0.3%)
U.K. (2)	**89.7%**	96.3%	(6.6%)
Australia	**90.0%**	96.9%	(6.9%)
Regulated Plants (1):			
Canada	**89.8%**	91.9%	(2.1%)

Notes:

(1) *Generating plant availability will fluctuate due to the timing and duration of outages.*

(2) *A planned outage commenced in March 2010 to repair a generator (refer to Unplanned Outage at Barking Generating Plant section).*

Plant Curtailment at Brighton Beach Generating Plant

On February 4, 2011, ATCO Power's Brighton Beach generating plant curtailed its output for preventative maintenance based on input from one of its equipment manufacturers. Examination of the plant's steam turbine has revealed cracking associated with the turbine blades. The outage to make an interim repair is likely to extend to the end of March 2011 with a permanent repair to be undertaken at a date yet to be determined. This curtailment is not expected to have a material impact on the Corporation's 2011 earnings.

Unplanned Outage at Barking Generating Plant

On October 25, 2007, ATCO Power's Barking generating plant in the U.K. experienced an unplanned outage due to a failure in a steam turbine generator. Temporary repairs were completed, and on March 6, 2008, ATCO Power announced that the plant had returned to service. In May 2010, a planned outage to finish the repairs to the generator was completed. ATCO Power received insurance proceeds associated with the business interruption and the cost of the repairs. Consequently, there was no significant impact to ATCO Power's 2010 earnings relating to this outage.

Other Power Generation Developments

In November 2008, ATCO Power announced it would design, build, own and operate a two unit 86 MW natural gas-fired simple cycle generating plant in Karratha, Western Australia. On February 14, 2010, the first unit commenced commercial operations followed by the second unit on April 9, 2010.

On January 30, 2008, the 150 MW Unit 4 at ATCO Power's Battle River generating plant experienced an unplanned outage due to a failure in the unit's generator. The unit returned to service on March 27, 2008. ATCO Power claimed relief under the force majeure provisions of its PPA. These provisions provide protection for the operator against mechanical failures which last more than forty-two days, except for circumstances where it is found that the operator failed to follow good operating practices. On July 11, 2008, the Balancing Pool notified ATCO Power that it disagreed with the claim. As settlement on the claim could not be reached with the PPA counterparty, the claim proceeded to arbitration. On October 25, 2010, the arbitrator issued a decision which denied ATCO Power's force majeure claim. As the impact of this outage had previously been recorded in 2008, the arbitrator's decision had no effect on the annual financial results for 2010.

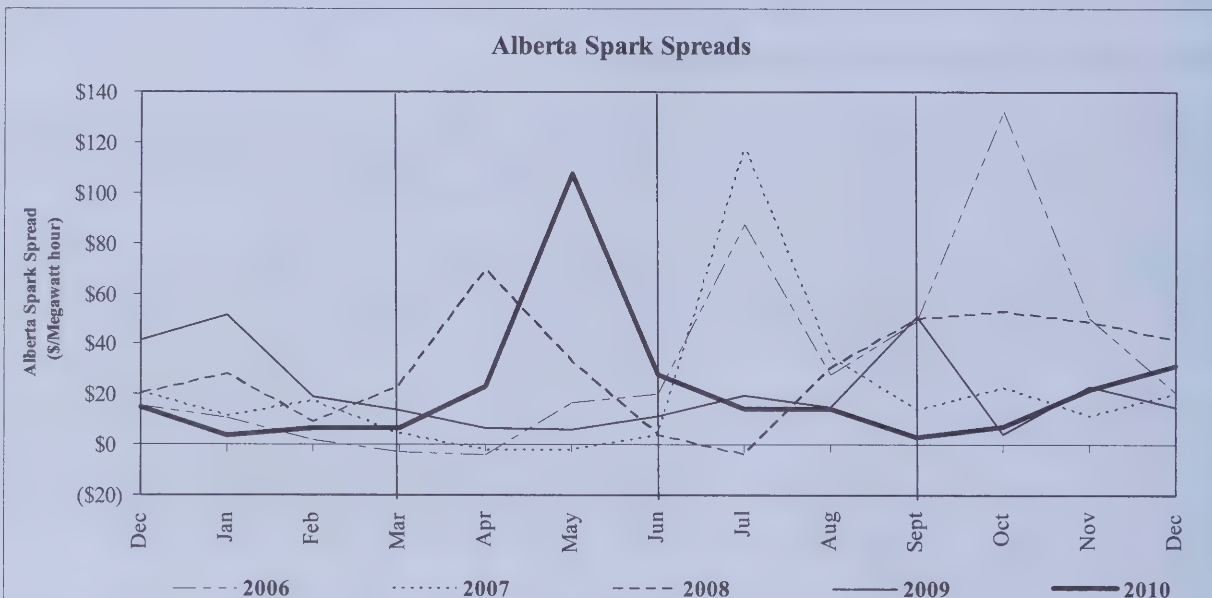
The majority of ATCO Power's electricity sales to the Alberta Power Pool are from natural gas-fired generating plants and, as a result, earnings are affected by natural gas prices and Alberta Power Pool prices. Alberta Power Pool electricity prices averaged \$50.88 per MWh in 2010, compared to average prices of \$47.81 per MWh in 2009. Natural gas prices averaged \$3.79 per GJ, compared to average prices of \$3.76 per GJ in 2009. These electricity and natural gas prices resulted in an average Spark Spread of \$22.49 per MWh in 2010, compared to \$19.58 per MWh in 2009.

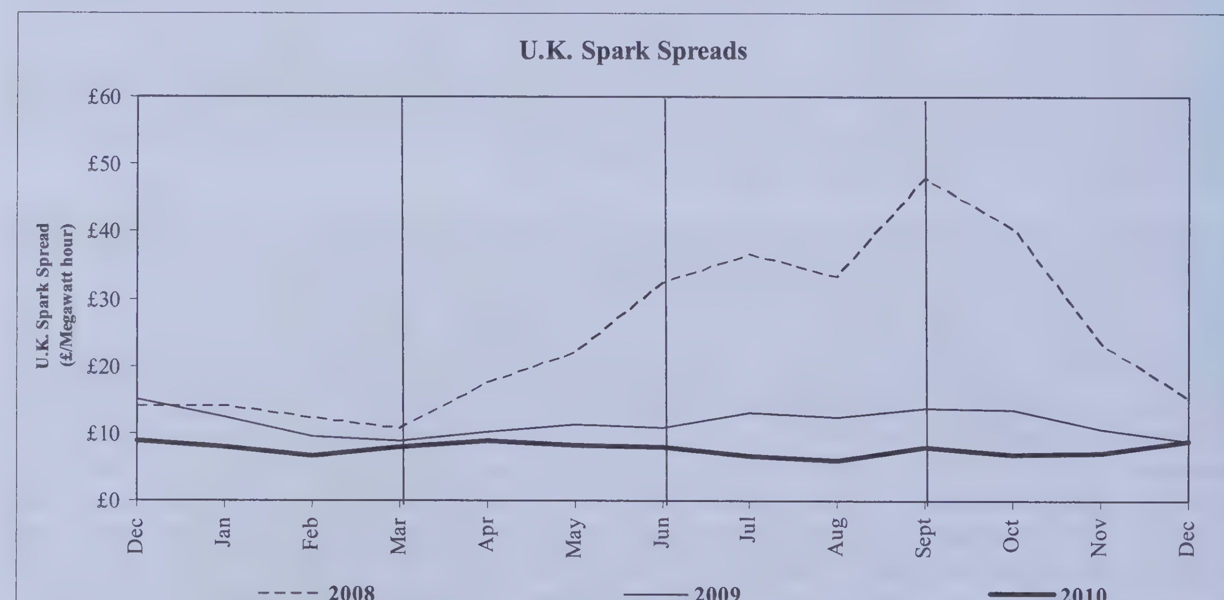
As of October 1, 2010, the majority of ATCO Power's Barking generating plant's capacity is exposed to the market prices for electricity, natural gas and emissions allowances. Power prices averaged £41.13 per MWh for the twelve months ended December 31, 2010, compared to average prices of £36.83 per MWh in the corresponding period of 2009. Natural gas prices averaged £3.98 per GJ for the twelve months ended December 31, 2010, compared to average prices of £2.94 per GJ in the corresponding period of 2009. Emissions allowance prices, which are traded in Euros, averaged £12.37 per tonne of CO_2 for the twelve months ended December 31, 2010, compared to average prices of £11.93 per tonne of CO_2, in the corresponding period of 2009. These electricity, natural gas and emissions allowance prices resulted in an average Spark Spread of £7.57 per MWh for the twelve months ended December 31, 2010, compared to average Spark Spreads of £11.28 per MWh in the corresponding period of 2009. Barking's actual merchant sales are not necessarily sold using the same Spark Spread indicator used in the graph below. The graph depicts the spot market whereas the Barking generating plant utilizes forward power sales to attain an element of cash flow certainty. ATCO Power owns 255 MW of the plant's capacity, of which 45 MW has been contracted for a one year term commencing October 1, 2010.

Changes in Spark Spread currently affect the results of approximately 437 MW of plant capacity owned in Alberta by ATCO Power out of a total Alberta-owned capacity of 1,738 MW and 210 MW of plant capacity owned in the U.K. by ATCO Power out of a total U.K.-owned capacity of 255 MW and a

worldwide owned capacity of 2,582 MW. As a result of the transfer of ATCO Resources to ATCO Power on January 1, 2011, Alberta and world-wide owned capacity increased by 229 MW to 1,883 MW and 2,811 MW, respectively. From January 1, 2011, changes in Spark Spreads affect the results of approximately 503 MW of Alberta-owned capacity.

The following charts demonstrates the volatility of Alberta Spark Spreads experienced by ATCO Power for the period of December 2005 to December 2010, and the volatility of the U.K. Spark Spreads for the period January 2008 to December 2010.





The Corporation's merchant power sales are affected by volatility in power and natural gas prices caused by market forces such as fluctuating supply and demand for electricity. The Corporation manages this volatility through its adoption of asset optimization strategies in accordance with its risk management policy for bidding its merchant power into both the Alberta and U.K. power markets.

Regulated Generating Plants

ATCO Power's Battle River and Sheerness generating plants were regulated by the AUC until December 31, 2000, but are now governed by legislatively mandated PPAs that were approved by the AUC. These plants are considered regulated operations primarily because the PPAs are designed to allow the owners of generating plants constructed before January 1, 1996, to recover their forecast fixed and variable costs and to earn a return at the rate specified in the PPAs. Each plant will become deregulated upon the earlier of one year after the expiry of its PPA or a decision to continue to operate the plant. For PPAs expiring prior to 2019, ATCO Power has one year after the expiry of a PPA to determine whether to decommission the generating plant in order to fully recover plant decommissioning costs or to continue to operate the plant and be responsible for decommissioning costs. For PPAs expiring after 2018, decommissioning costs are the responsibility of the plant owner. Each PPA is to remain in effect until the earlier of the last day of the estimated life of the related generating plant or December 31, 2020.

The electricity generated by the Battle River and Sheerness generating plants is sold pursuant to PPAs. Under the PPAs, ATCO Power is required to make the generating capacity for each generating unit available to the purchaser of the PPA for that unit. In return, ATCO Power is entitled to recover its forecast fixed and variable costs for that unit from the PPA purchaser, including a rate of return on common equity equal to the long term Government of Canada bond rate plus 4.5% based on a deemed common equity ratio of 45%. Many of the forecast costs will be determined by indices, formulae or other means for the entire period of the PPA. ATCO Power's actual results will vary and depend on performance compared to the forecasts on which the PPAs were based. The return on common equity rate used in its PPA tariff calculations for ATCO Power was 8.44% in 2010 and 8.64% for 2009. The rate of return on common equity for 2011 is 7.90%.

Under the terms of the PPAs, ATCO Power is subject to an incentive/penalty regime related to generating unit availability. Incentives are payable by the PPA counterparties for availability in excess of predetermined targets, and penalties are payable by ATCO Power when the availability targets are not achieved. These amounts are amortized based on estimates of future generating unit availability and future electricity prices over the term of the PPAs.

Accumulated incentives in excess of accumulated penalties are deferred. For any of the individual PPAs, should accumulated incentives plus estimated future incentives exceed accumulated penalties plus estimated future penalties, the excess will be amortized to revenues on a straight-line basis over the remaining term of the PPAs. Should accumulated penalties plus estimated future penalties exceed accumulated incentives plus estimated future incentives, the shortfall will be expensed in the year the shortfall occurs.

During 2010, the **deferred availability incentive** account decreased by $18.9 million to $48.2 million, mainly due to availability penalties paid associated with the planned outage in the second quarter of 2010 for the Battle River generating plant, which occurred during a period of high Alberta Power Pool electricity prices, as well as normal amortization. The amortization of deferred availability incentives, recorded in revenues, decreased by $2.2 million to $14.1 million, primarily as a result of the impact of 2010 planned outages and lower forecast prices for electricity.

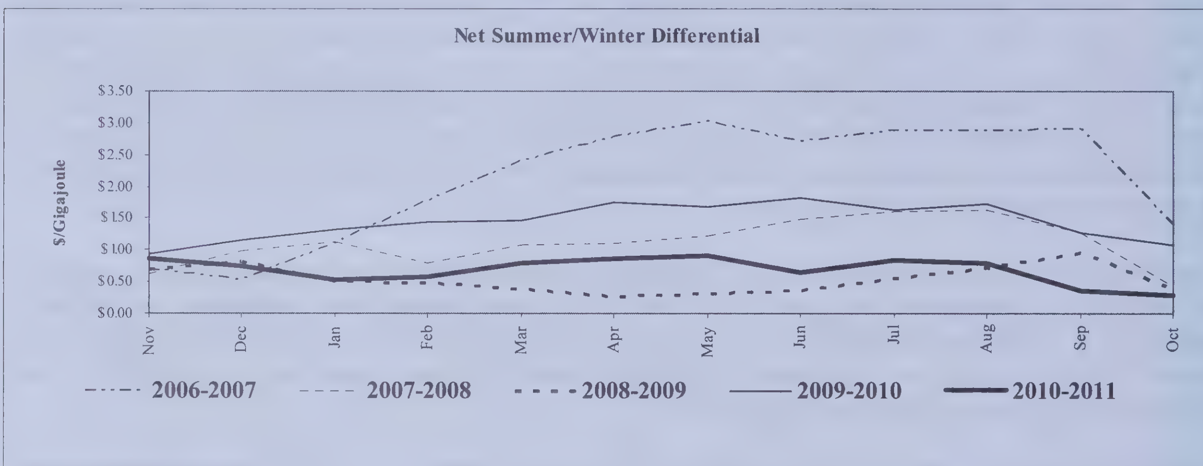
ATCO Midstream

ATCO Midstream engages in non-regulated natural gas gathering, processing, storage and natural gas liquids extraction services and sales.

Storage Operations

The majority of ATCO Midstream's natural gas storage revenues come from seasonal differences (summer/winter) in the price of natural gas (Storage Price Differentials).

Storage Price Differentials can be volatile, as shown in the following graph, which illustrates a range of seasonal differentials experienced during the storage periods from the 2006-2007 storage year to the 2010-2011 storage year. Storage Price Differentials at any point in time may not always be indicative of the storage revenue and earnings for the same period due to the types of contracts and the timing of the revenue recognition associated with these contracts.

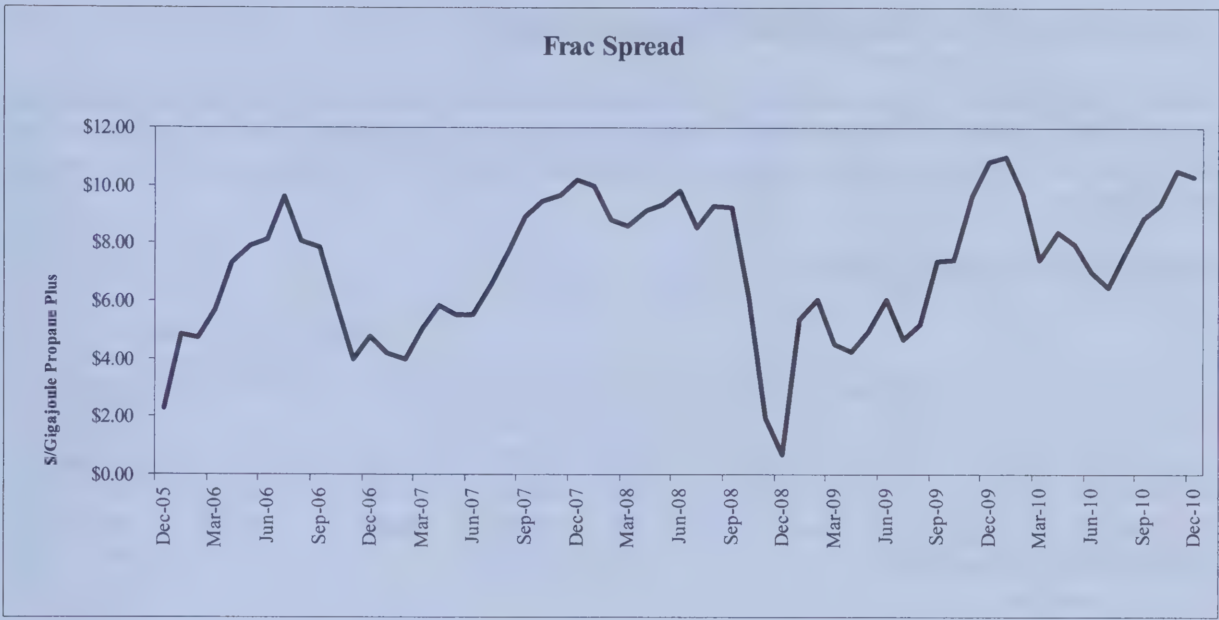


Fluctuations in Storage Price Differentials affect ATCO Midstream's earnings and cash flow from operations. At current values, a $0.25 change in the Storage Price Differentials impacts ATCO Midstream's annual earnings by approximately $8.0 million.

NGL Extraction Operations

A portion of ATCO Midstream's revenues is derived from the extraction of NGL from natural gas and the marketing of NGL products under supply or marketing contracts. ATCO Midstream owns a net working interest of 411 million cubic feet per day of processing capacity in its NGL extraction plants.

ATCO Midstream's NGL extraction operations involve the extraction of NGL from natural gas and the replacement (on a heat content equivalent basis) of the NGL extracted with shrinkage gas. For Propane Plus, the difference between the price of natural gas and the value of the liquids extracted is commonly referred to as the Frac Spread. Frac Spreads vary with fluctuations in the price of natural gas and the prices of the applicable liquids extracted. Frac Spreads can be volatile, as shown in the following graph, which illustrates monthly Frac Spreads during the period of December 2005 to December 2010.



Note:

(1) *The above chart represents measurements of industry Frac Spreads in Alberta, as reported by an independent consultant. The average Frac Spread for 2010 was $8.33 per gigajoule compared to $6.36 per gigajoule in 2009.*

Fluctuations in Frac Spreads affect ATCO Midstream's earnings and cash flow from operations. At current volumes, a $1.00 change in the average annual Frac Spread impacts ATCO Midstream's annual earnings by approximately $6.0 million.

Corporate & Other

In 2010, **Adjusted Earnings** were $41.0 million, an **increase** of $9.8 million (31%) over 2010, primarily due to cost efficiencies in ATCO I-Tek, partially offset by higher share appreciation rights expense resulting from changes in the Corporation's Class A Share prices since January 1, 2010.

ATCO I-Tek

ATCO I-Tek is engaged in the development, operation and support of information systems and technologies.

ATCO I-Tek provides billing, payment processing, credit, collection and call centre services to its clients. ATCO I-Tek currently provides such services to Direct Energy for its regulated retail and competitive energy supply businesses in Alberta. In addition, ATCO I-Tek supplies distribution-related billing and customer care services to ATCO Gas and ATCO Electric.

Direct Energy entered into a 10 year contract effective May 4, 2004, with ATCO I-Tek to provide billing and call centre services to ensure continued quality customer service. Direct Energy has the ability to terminate this contract after the fifth anniversary, which occurred on May 4, 2009, upon immediate payment of termination fees which decline over the remaining term of the contract. As a result of negotiations in 2010, the contract was extended to December 31, 2014.

Liquidity and Capital Resources

A major portion of the Corporation's operating income and funds generated by operations is generated from its utility operations. Canadian Utilities and its wholly owned subsidiary, CU Inc., use short term bank loans and commercial paper borrowings to provide flexibility in the timing and amounts of long term financing.

SUMMARY OF CASH FLOW

	For the Year Ended December 31		
($ millions)	**2010**	2009	Change to 2010 (2010-2009)
Cash position, beginning of period	**796.0**	726.6	10%
Cash provided by (used in)			
Operating activities:			
Funds Generated by Operations	**738.2**	793.4	(7%)
Changes in non-cash working capital	**26.1**	(55.1)	147%
Cash flow from operations	**764.3**	738.3	4%
Investing activities	**(777.5)**	(852.1)	9%
Financing activities	**(232.3)**	197.0	(218%)
Foreign currency impact on cash balances	**(10.9)**	(4.9)	(122%)
Decrease in cash on ATCO Structures & Logistics Transaction	-	(8.9)	-
Cash position, end of period	**539.6**	796.0	(32%)

OPERATING ACTIVITIES

Funds Generated by Operations were $738.2 million in 2010, a **decrease** of $55.2 million (7%) compared to 2009. This decrease was primarily due to availability penalties paid by ATCO Power due to a planned outage in the Battle River generating plant and changes in non-current regulatory deferral amounts in the Utilities which vary from quarter to quarter and are, therefore, not comparable or indicative of Funds Generated by Operations on an annual basis. In 2010, **changes in non-cash working capital** were $26.1 million, an **increase** of $81.2 million (147%) over 2009. This increase reflects reduced accounts receivable from natural gas storage operations in ATCO Midstream and the receipt of amounts owing to ATCO Power in 2009 as a result of the H.R. Milner Income Tax Reassessment.

INVESTING ACTIVITIES

In 2010, **cash used in investing activities decreased** by 9% compared to 2009, mainly due to lower capital expenditures.

Capital expenditures in 2010 **decreased** by $77.1 million compared to 2009. This decrease was primarily due to decreased investment in non-regulated electric transmission projects by ATCO Energy Solutions and lower costs incurred to complete the Karratha plant in the second quarter of 2010.

Capital Expenditures	**For the Year Ended December 31**		
($ millions)	**2010**	2009	Change to 2010 (2010-2009)
Utilities	**788.9**	776.1	2%
Energy	**67.1**	151.5	(56%)
Corporate & Other	**13.0**	18.5	(30%)
	869.0	946.1	(8%)

Capital expenditures to maintain capacity, meet planned growth, and fund future development activities are expected to be approximately $1.6 billion in 2011, an increase of $0.7 billion over 2010. The majority of these expenditures relate to the Utilities Segment. For the 2011 to 2013 period, capital expenditures in the Utilities Segment are expected to be approximately $5.0 billion to $6.0 billion (refer to Segmented Information – Utilities – Regulatory Developments – ATCO Electric – Transmission Infrastructure Projects section). These expenditures are expected to be financed by a combination of funds generated by operations and capital market financings.

The planned capital expenditures for the Utilities Segment are based on the following significant assumptions:

- the projects identified by the AESO will proceed as currently scheduled;
- the remaining planned capital expenditures in the Utilities Segment are required to maintain safe and reliable capacity and meet planned growth in the Utilities' service areas. These expenditures are consistent with the anticipated growth in the Alberta economy and in the Utilities' service areas;
- the regulatory system in Alberta will remain substantially unchanged; and
- continued access to capital market financings.

In the opinion of the Corporation, these assumptions are reasonable, but no assurance can be given that these assumptions will prove to be correct.

The Utilities are subject to the normal risks faced by companies that are regulated. These risks include the approval by the AUC of customer rates that permit a reasonable opportunity to recover on a timely basis the estimated costs of providing service, including a fair return on rate base. In addition, these risks include the disallowance of capital expenditures incurred if the AUC determines that such costs were not prudently incurred. This risk is mitigated by the inclusion of capital expenditures in general rate applications approved by the AUC. Furthermore, all major electric transmission projects assigned by the AESO to ATCO Electric are required to be approved by the AUC prior to commencing construction.

The Corporation is subject to the normal risks associated with major capital projects including delays and cost overruns. Although the Corporation attempts to mitigate these risks by careful planning and entering into long term contracts when possible, there can be no assurance that significant cost overruns or delays will not occur.

FINANCING ACTIVITIES

In 2010, the Corporation had **net debt decreases** of $111.8 million. **Redemptions** included $125.0 million of 11.40% Debentures due August 15, 2010, $50.1 million of other long term debt and $61.7 million of non-recourse long term debt. **Issuance** of debt was comprised of $125.0 million of 4.947% Debentures due November 18, 2050.

On December 2, 2010, CU Inc., a wholly owned subsidiary of the Corporation, **issued** $75.0 million of 3.80% Cumulative Redeemable Preferred Shares Series 4. In 2009, CU Inc. **issued** $160.0 million of 6.70% Cumulative Redeemable Preferred Shares Series 2.

On March 1, 2010, the Corporation commenced a **normal course issuer bid** for the purchase of up to 3% of the outstanding Class A Shares. The bid will expire on February 28, 2011. From March 1, 2010, to December 31, 2010, 138,850 shares were purchased.

Purchases of the Class A Shares under the normal course issuer bid were $6.5 million in 2010, compared to nil in 2009. **Issues** of Class A Shares due to stock option exercises were $5.4 million in 2010 compared to $6.4 million in 2009. **Net purchases** were $1.1 million in 2010, compared to **net issues** of $6.4 million in 2009.

Total **dividends increased** by 7% to $190.0 million. In 2010, the **quarterly dividend** payment on the Corporation's Class A and Class B Shares was **increased** by $0.025 to $0.3775 per share over 2009. On January 13, 2011, the Board of Directors declared the first quarter dividend of $0.4025 per share. The Corporation has increased its annual common share dividend each year since its inception as a holding company in 1972. The payment of any dividend is at the discretion of the Board of Directors and depends on the financial condition of the Corporation and other factors.

FOREIGN CURRENCY TRANSLATION

Foreign currency translation decreased the Corporation's cash position by $10.9 million due to changes in U.K. and Australian exchange rates used for balance sheet translations.

SHORT TERM INVESTMENT POLICY

The Corporation has a long-standing policy not to invest any of its cash balances in asset-backed securities. Cash and short term investment credit risk is reduced by investing approximately 73% in short term money market instruments of Canadian financial institutions and Government of Canada treasury bills as at December 31, 2010.

LINES OF CREDIT

At December 31, 2010, the Corporation had the following credit lines that enable it to obtain funding for general corporate purposes.

($ millions)	Total	Used	Available
Long term committed	326.0	3.0	323.0
Short term committed	600.0	35.8	564.2
Uncommitted	53.7	7.6	46.1
Total	979.7	46.4	933.3

The Corporation's long term committed lines of credit include:

- A $200 million unsecured revolving extendible term credit facility of Canadian Utilities established in 1999 with a syndicate of Canadian chartered banks. This facility will expire in June 2013, unless extended at the option of the lenders;
- A $100 million unsecured revolving extendible term credit facility of ATCO Midstream established in 1999 with a syndicate of Canadian chartered banks and financial institutions. This facility will expire in August 2013, unless extended at the option of the lenders; and
- A $26 million revolving credit facility of ATCO Power with a Canadian chartered bank. This facility will expire in August 2013, unless extended at the option of the lenders.

The Corporation's short term committed lines of credit include:

- A $300 million unsecured revolving extendible credit facility of CU Inc. established in 1999 with a syndicate of Canadian chartered banks. This facility is used as a backstop for CU Inc.'s commercial paper program and for occasional issues of letters of credit. This facility will expire in July 2011, unless extended at the option of the lenders; and
- A $300 million unsecured revolving extendible credit facility of Canadian Utilities established in 1999 with a syndicate of Canadian chartered banks. This facility is used as a backstop for Canadian Utilities' commercial paper program. This facility will expire in July 2011, unless extended at the option of the lenders.

The Corporation's uncommitted lines of credit are primarily used by its subsidiaries for liquidity purposes and for issues of letters of credit. Most of these facilities are unsecured, but some are secured by charges over assets of particular subsidiaries.

The amount and timing of future financings will depend on market conditions and the specific needs of the Corporation.

CONTRACTUAL OBLIGATIONS

Contractual obligations for the next five years and thereafter are as follows:

	Payments Due by Period				
	Total	Less than 1 Year	1-3 Years	4-5 Years	After 5 Years
($ millions)					
Accounts payable and accrued liabilities	404.9	404.9	-	-	-
Operating leases	101.0	21.5	28.7	22.3	28.5
Long term debt	3,077.8	103.3	146.8	227.7	2,600.0
Non-recourse long term debt	346.6	38.3	69.3	53.8	185.2
Interest expense [(1)]	3,087.8	210.8	399.9	372.3	2,104.8
Purchase obligations:					
Coal purchase contracts [(2)]	711.2	66.3	132.7	164.0	348.2
Natural gas purchase contracts [(3)]	33.8	13.2	20.4	0.2	-
Operating and maintenance agreements [(4)]	120.4	19.9	38.2	32.0	30.3
Capital expenditures [(5)]	88.3	88.3	-	-	-
Derivatives[(6)]	8.0	2.8	2.8	1.4	1.0
Other	28.6	9.0	16.3	3.1	0.2
Total	8,008.4	978.3	855.1	876.8	5,298.2

Notes:

(1) *Interest payments on floating rate debt that has not been hedged have been estimated using rates in effect at December 31, 2010. Interest payments on debt that has been hedged have been estimated using the hedged rates.*

(2) *ATCO Power has fixed price long term contracts to purchase coal for its coal-fired generating plants. These costs are recoverable pursuant to the PPAs.*

(3) *Natural gas purchase contracts consist primarily of ATCO Power contracts to purchase natural gas for certain of its natural gas-fired generating plants. ATCO Power has long term offtake agreements with the purchasers of the electricity to recover 100% of these costs. The ATCO Power merchant component of its generating plants in Alberta and the U.K. does not have any long term contracts to purchase natural gas.*

(4) *ATCO Power has various contracts with suppliers to provide operating and maintenance services at certain of its generating plants.*

(5) *Various contracts to purchase goods and services with respect to capital expenditure programs.*

(6) *Payments on outstanding derivatives have been estimated using rates in effect at December 31, 2010.*

BASE SHELF PROSPECTUS

On May 18, 2010, CU Inc. filed a **base shelf prospectus** that permits CU Inc. to issue up to an aggregate of $1,700.0 million of debentures over the twenty-five month life of the prospectus. On November 18, 2010, CU Inc. issued $125.0 million of 4.947% Debentures due November 18, 2050, leaving $1,575.0 million remaining.

The proceeds of this issue were advanced to ATCO Electric to be used to fund capital expenditures.

Share Capital

The equity securities of the Corporation consist of Class A Shares and Class B Shares.

At February 18, 2011, the Corporation had outstanding 87,075,850 Class A Shares, 40,409,949 Class B Shares and options to purchase 699,050 Class A Shares.

CLASS A NON-VOTING SHARES AND CLASS B COMMON SHARES

The owners of the Class A Shares and the Class B Shares are entitled to share equally, on a share for share basis, in all dividends declared by the Corporation on either of such classes of shares as well as the remaining property of the Corporation upon dissolution. The owners of the Class B Shares are entitled to vote and to exchange at any time each share held for one Class A Share.

If a take-over bid is made for the Class B Shares which would result in the offeror owning more than 50% of the outstanding Class B Shares and which would constitute a change in control of the Corporation, owners of Class A Shares are entitled, for the duration of the bid, to exchange their Class A Shares for Class B Shares and to tender such Class B Shares pursuant to the terms of the take-over bid. Such right of exchange is conditional upon the completion of the take-over bid giving rise to the right of exchange, and if the take-over bid is not completed, then the right of exchange shall be deemed never to have existed. In addition, owners of the Class A Shares are entitled to exchange their shares for Class B Shares if ATCO Ltd., the present controlling share owner of the Corporation, ceases to own or control, directly or indirectly, more than 10,000,000 of the issued and outstanding Class B Shares In either case, each Class A Share is exchangeable for one Class B Share, subject to changes in the exchange ratio for certain events such as a stock split or rights offering.

Of the 6,400,000 Class A Shares authorized for grant in respect of options under the Corporation's stock option plan, 2,946,200 Class A Shares are available for issuance at December 31, 2010. Options may be granted to officers and key employees of the Corporation and its subsidiaries at an exercise price equal to the weighted average of the trading price of the shares on the Toronto Stock Exchange for the five trading days immediately preceding the date of grant. The vesting provisions and exercise period (which cannot exceed 10 years) are determined at the time of grant. As of February 18, 2011, options to purchase 699,050 Class A Shares were outstanding.

Business Risks

ENERGY PRICES

A combination of an increasing power reserve margin (the amount of power supply in excess of demand) and low natural gas prices has led to a decrease in Alberta and U.K. power prices and the commensurate Spark Spreads. This affects approximately 503 MW of merchant power capacity owned in Alberta by ATCO Power out of a total Alberta-owned capacity of approximately 1,883 MW and since October 1, 2010, 210 MW of merchant power capacity owned in the U.K. by ATCO Power out of a total U.K.-owned capacity of 255 MW.

The Corporation is unable to determine what future changes in energy markets could occur and how these changes could affect the Corporation.

PENSION PLANS

Employees are required to contribute a percentage of their salary to registered pension plans. The Corporation is required to contribute its share of contributions on behalf of the defined contribution members of the pension plans and to provide the balance of the funding necessary to ensure that benefits will be fully provided for at retirement for the members of the defined benefit pension plans.

Declines in stock and bond markets, changes in actuarial assumptions and additional employee service have created funding deficits in the Corporation's defined benefit pension plans. Prior to 2010, the Corporation had not made material contributions since April 1, 1996, as a result of the defined benefit plans' surplus position. In addition the Corporation had obtained regulatory approval to fund the employer's contributions to the defined contribution component of the pension plan from the defined benefit plan surplus.

Material current service and deficit funding contributions resumed in 2010. The actual funding contributions for 2010 were established based on actuarial valuations for funding purposes as of December 31, 2009. Based on these final actuarial valuations, the employer contributions relating to both the defined contribution and the defined benefit components of the plan for 2010 were approximately $71 million. Contributions commenced during the first quarter of 2010. The next actuarial valuation for funding purposes is required to be completed as of December 31, 2012.

For purposes of any pension funding requirements pertaining to utility operations, the AUC has directed that the cash basis of accounting be used in customer rate applications. Accordingly, the Corporation includes the cost of funding in its rate applications to the AUC, thereby, with the consent of the AUC, recovering approximately 78% of the costs of funding its pension plans from utility customers (refer to Segmented Information – Utilities section). The net funding contribution amounts (actual funding contributions less recovery from utility customers) were approximately $16 million. Pension funding contributions do not equate to pension expense for accounting purposes. A description of pension expense can be found in Note 21 of the Corporation's consolidated financial statements for the year ended December 31, 2010.

FINANCING

The Corporation's financing risk relates to the price volatility and availability of external financing to fund the capital expenditure program and refinance existing debt maturities. Financing risk is directly influenced by market factors. As financial market conditions change, this can affect the availability of capital and also the relevant financing costs.

To address this risk, the Corporation manages its capital structure to maintain strong credit ratings which allows the Corporation continued access to the capital markets. The Corporation also maintains sufficient liquidity through cash balances and committed credit facilities to ensure that obligations are paid when due. The Corporation's primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper and draws under committed credit facilities, and access to capital markets.

As at December 31, 2010, the Corporation had cash balances of approximately $540 million and available committed and uncommitted lines of credit of approximately $0.9 billion which can be utilized for general corporate purposes.

ENVIRONMENTAL MATTERS

The Corporation's operating subsidiaries and the industries in which they operate are subject to extensive federal, provincial and local environmental protection laws concerning emissions to the air, discharges to surface and subsurface waters, land use activities and the handling, manufacturing, processing, use, emission and disposal of materials and waste products.

Greenhouse Gas Emissions

Alberta legislation requires most large emitters to reduce GHG emission intensities by up to 12% as compared to a baseline for the 2003 to 2005 period. For cogeneration facilities, steam production GHG emissions are also subjected to the same 12% reduction target, however these facilities are eligible for special GHG treatment and emissions credits.

Compliance reports for any GHG obligations must be submitted annually to Alberta Environment by March 31 for the previous calendar year. The settlement of the obligation will be achieved through a combination of approved compliance options including: improved unit performance, emission performance credits, offset credits and technology fund credits. PPA counterparties have reimbursed ATCO Power for amounts relating to their GHG obligations. Due to lower emissions per unit of output, ATCO Power's gas-fired generating units have minimal exposure to Alberta's GHG regulation and some of the cogeneration facilities generated emission performance credits which can be used for internal compliance as noted above.

ATCO Power participated in a working group established by Alberta Environment tasked with reviewing the method used to determine the GHG obligation for cogeneration units. A new method is expected in early 2011 that will apply to the 2011 reporting year, and could have an impact on ATCO Power's cogeneration plants. Until this methodology is finalized, the impact cannot be determined.

The Government of Canada has announced plans to reduce GHG emissions in the electricity sector by moving forward with regulations on coal-fired generation. Draft regulations are expected to be published in early 2011. Regulations are scheduled to come into effect on July 1, 2015. The approach would apply a "clean as gas" performance standard to new coal-fired generation units and units that have reached the end of their economic life, currently deemed as 45 years from the unit's commissioning date. The government has indicated that appropriate options will be considered in the process of developing the regulations and in the determination of the end-of-life date.

As inscribed in the Copenhagen Accord, Canada has aligned its GHG target with the United States at a 17% reduction from 2005 levels by 2020. It is not clear how this commitment could impact the electricity sector beyond the proposed coal regulation. Accordingly, significant regulatory uncertainty and a wide range of potential outcomes remain. ATCO Power continues to monitor and actively engage the federal government in this area to manage the associated risks.

It is anticipated that, once the federal GHG program is finalized, the Alberta GHG program will be harmonized to the federal program.

The Barking generating plant in the U.K. complies with the European Union Emissions Trading Scheme (EU-ETS) which is currently in its second phase until the end of 2012. Under this second of three phases, Barking is allocated a free allowance of 1.4 million tonnes towards total annual emissions of up to 2.8 million tonnes. Until September 30, 2010, Barking's long term power purchasers were responsible for 72.5% of the plant's emissions and they received a pro-rata share of the free allocation. The remaining free allocations were applied to the sale of merchant energy to the market. Since October 1, 2010, Barking sells its free allocations to the EU-ETS market. Barking then purchases emissions allowances from the

EU-ETS market, as required, on a forward basis concurrently with forward power sales. This approach currently provides a full recovery of these emissions compliance costs.

ATCO Power's Australian generating plants are expected to be regulated by an Australian Government carbon pollution reduction scheme. All of ATCO Power's Australian plants have long term contractual power purchase arrangements allowing full recovery of costs associated with complying with any emissions regulations.

Air Pollutants

Alberta regulation requires coal-fired generating plant operators, including ATCO Power, to monitor mercury emissions and target a capture of at least 70% of the mercury in the coal commencing January 1, 2011. Alberta Environment approved the Corporation's proposed solution and mercury control equipment was installed at the Battle River and Sheerness generating plants.

The Clean Air Strategic Alliance conducted a review of air emissions standards (sulphur dioxide, nitrogen oxides, mercury, and particulate matter) for the power generation sector in Alberta. The Corporation participated in this process which will develop new air emissions standards for new units and units at the end of their design life (40 years or the end of their PPA term for coal-fired units and 30 years for natural gas-fired units). The new standards are expected to be adopted by Alberta Environment to be effective in 2011.

In October 2010, federal and provincial environment ministers agreed to move forward with a new air management approach. The proposed new system will include more ambitious air quality standards and consistent industrial emissions standards across Canada. Ministers have directed officials to develop the major elements of the system in 2011 with implementation to start in 2013. The Corporation is represented in the regulatory consultation process through the Canadian Electricity Association and is also participating in the working groups that have been set up to assist with the development of this air management system. It is uncertain how a federal system would impact the existing provincial frameworks.

Cost Recovery

It is anticipated that the PPAs will allow ATCO Power to recover all of the costs associated with complying with both the federal and Alberta regulations during the PPA terms. An exception to this recovery is for the emissions related to output in excess of the committed capacity in the PPAs. The amount of emissions related to output in excess of this committed capacity is minimal. The Corporation expects to recover the majority of compliance costs for its gas-fired plants through the market. Market recovery will depend on the degree to which the Corporation's competitors face similar or greater costs.

The Corporation continues to monitor these developments and the impact of complying with any resulting regulations.

PIPELINE INTEGRITY

Recent pipeline ruptures in the U.S. have highlighted the risks associated with pipeline integrity. Although the probability of an occurrence is very low, the consequences of a failure can be extreme. ATCO Pipelines, ATCO Gas and ATCO Midstream, by the nature of their businesses, have significant pipeline infrastructure that has operated safely and effectively for decades. The Corporation continues to assess the integrity of its pipeline infrastructure.

CARBON NATURAL GAS STORAGE FACILITY

In the normal course of operation, the Carbon Facility is subject to drainage. In an effort to protect the Carbon Facility from drainage, ATCO Gas monitors operating pressures and from time to time commissions studies to help protect the integrity of the Carbon Facility. In those instances where it has been deemed necessary, ATCO Gas has undertaken an acreage protection program whereby it acquires the rights to surrounding properties to protect the integrity of the Carbon Facility by either minimizing or eliminating the effects of drainage.

REGULATED OPERATIONS

Regulated operations are conducted by the Corporation's wholly owned subsidiary, CU Inc., which in turn has the following subsidiaries: ATCO Electric and its subsidiaries, ATCO Gas and ATCO Pipelines. ATCO Power's two largest generating plants are also considered regulated operations because they are governed by legislatively mandated PPAs, which were approved by the AUC.

The Utilities are subject to the normal risks faced by companies that are regulated. These risks include the approval by the AUC of customer rates that permit a reasonable opportunity to recover on a timely basis the estimated costs of providing service, including a fair return on rate base. In addition, these risks include the disallowance by the AUC, of costs incurred. The Utilities' ability to recover the actual costs of providing service and to earn the approved rates of return depends on achieving the forecasts established in the rate-setting process. The determination of fair rate of return on the common equity component of rate base is an earnings and cash flow risk for the Utilities and is currently the subject of the 2011 Generic Cost of Capital proceeding (refer to Annual Results of Operations – Segmented Information – Utilities section).

Benchmarking

The Utilities purchase information technology services from ATCO I-Tek. ATCO Electric and ATCO Gas also purchase customer care and billing services from ATCO I-Tek. The recovery of these costs in customer rates is subject to AUC approval. Since 2003, the costs have been approved on a Placeholder basis. An AUC decision was issued on March 8, 2010, which addressed the 2003-2007 Placeholder amounts for the Utilities. The AUC decision approved the adjustments to the Placeholder amounts as filed based on fair market value resulting in no material changes to earnings.

For the 2008 and 2009 period, a separate regulatory process has been established to approve rates for information technology and customer care and billing services provided by ATCO I-Tek that can be included in customer rates. The proceeding is scheduled to be completed in the first quarter of 2011 and a decision is expected in the second quarter of 2011.

A further regulatory process to deal with rates for information technology and customer care and billing services provided by ATCO I-Tek for 2010 and beyond has been established and the AUC is expected to set a schedule for this regulatory process after the completion of the 2008 – 2009 process.

In addition to the rates, this process includes the review of three options for the future provision of information technology and customer care and billing services. The options are (i) the repatriation of these services back into the Utilities; (ii) moving to a third party service provider; or (iii) renewing with ATCO I-Tek, the current service provider. On December 11, 2009, the AUC issued a decision approving the implementation of the new Master Service Agreements (excluding the rates therein) with ATCO I-Tek for information technology and customer care and billing services effective January 1, 2010, for an interim period, the term of which will be determined in the upcoming regulatory process.

Transfer of the Retail Energy Supply Businesses

In 2004, ATCO Gas and ATCO Electric transferred their retail energy supply businesses to Direct Energy and one of its affiliates (collectively, Direct Energy), a subsidiary of Centrica plc. ATCO Gas and ATCO Electric continue to own and operate the natural gas and electricity distribution systems used to deliver energy.

Although ATCO Gas and ATCO Electric transferred to Direct Energy certain retail functions, including the supply of natural gas and electricity to customers and billing and customer care functions, the legal obligations of ATCO Gas and ATCO Electric remain if Direct Energy fails to perform. In certain events (including where Direct Energy fails to supply natural gas and/or electricity and ATCO Gas and/or ATCO Electric are ordered by the AUC to do so), the functions will revert to ATCO Gas and/or ATCO Electric with no refund of the transfer proceeds to Direct Energy by ATCO Gas and/or ATCO Electric.

Centrica plc, Direct Energy's parent, has provided a \$300 million guarantee, supported by a \$235 million letter of credit in respect of Direct Energy's obligations to ATCO Gas, ATCO Electric and ATCO I-Tek in respect of the ongoing relationships contemplated under the transaction agreements. However, there can be no assurance that the coverage under these agreements will be adequate to cover all of the costs that could arise in the event of a reversion of such functions.

Canadian Utilities has provided a guarantee of ATCO Gas', ATCO Electric's and ATCO I-Tek's payment and indemnity obligations to Direct Energy contemplated under the transaction agreements.

Measurement Inaccuracies in Metering Facilities

Measurement inaccuracies occur from time to time with respect to the Utilities' metering facilities. Measurement adjustments are settled between parties based on the requirements of the Electricity and Gas Inspections Act (Canada) and applicable regulations issued pursuant thereto. There is a risk of disallowance of the recovery of a measurement adjustment if controls and timely follow up are found to be inadequate by the AUC.

Regulated Generating Plants

ATCO Power has two regulated operations, the Battle River and Sheerness generating plants, which were regulated by the AUC until December 31, 2000, but are now governed by legislatively mandated PPAs that were approved by the AUC. These plants are included in regulated operations primarily because the PPAs are designed to allow the owners of generating plants constructed before January 1, 1996, to recover their forecast fixed and variable costs and to earn a return at the rate specified in the PPAs. The plants will become deregulated upon the earlier of one year after the expiry of a PPA or a decision to continue to operate the plant. For PPAs expiring prior to 2019, ATCO Power has one year after the expiry of a PPA to determine whether to decommission the generating plant in order to fully recover plant decommissioning costs or to continue to operate the plant. For PPAs expiring after 2018 decommissioning costs are the responsibility of the plant owner. Each PPA is to remain in effect until the earlier of the last day of the estimated life of the related generating plant or December 31, 2020.

The electricity generated by the Battle River and Sheerness generating plants is sold pursuant to PPAs. Under the PPAs, ATCO Power is required to make the generating capacity for each generating unit available to the purchaser of the PPA for that unit. In return, ATCO Power is entitled to recover its forecast fixed and variable costs for that unit from the PPA purchaser, including a return on common equity equal to the long term Government of Canada bond rate plus 4.5% based on a deemed common equity ratio of 45%. Many of the forecast costs will be determined by indices, formulae or other means

for the entire period of the PPA. ATCO Power's actual results will vary and depend on performance compared to the forecasts on which the PPAs were based.

Fuel costs for the Battle River and Sheerness generating plants are mostly for coal supply. To protect against volatility in coal prices, ATCO Power owns or has sufficient coal supplies under long term contracts for the anticipated lives of its Battle River and Sheerness coal-fired generating plants. These contracts are at prices that are either fixed or indexed to inflation.

NON-REGULATED OPERATIONS

Independent Power Plants

The Corporation's portfolio of non-regulated electric generating plants is made up of gas-fired cogeneration, gas-fired combined cycle and gas-fired simple cycle plants as well as a small hydro plant. The majority of operating income from power generation operations is derived through long term power, steam and transmission support agreements. Where long term agreements are in place, the purchaser assumes the fuel supply and price risks and the Corporation, under these agreements, assumes the operating risks.

ATCO Power's generating plants include high efficiency gas-fired cogeneration plants, with associated on-site steam and power tolling arrangements, and gas-fired peaking and hydroelectric plants with underlying transmission support agreements. For the first nine months of 2010, sales from approximately 69% of ATCO Power's generating capacity were subject to long term agreements, while the remaining 31% consisted primarily of sales to the Alberta Power Pool and the U.K. merchant power market. On September 30, 2010, the Barking power plant revenue contracts expired reducing the contracted capacity to approximately 63%, net of increased capacity at the Muskeg River plant. The U.K. and Alberta merchant sales are dependent on prices in the Alberta electricity spot market and in the U.K. merchant power market. The majority of the electricity sales to the Alberta Power Pool are from gas-fired generating plants, and as a result, operating income is affected by natural gas prices. During peak electricity usage hours in Alberta, a correlation exists between electricity spot prices and natural gas spot prices. During off-peak hours, there is less correlation.

Changes and volatility in Alberta Power Pool electricity prices, natural gas prices and related Spark Spreads may have a significant impact on the Corporation's earnings and cash flow from operations in the future. The Corporation manages this volatility through its adoption of asset optimization strategies in accordance with its risk management policy for bidding its merchant power into both the Alberta and U.K. power markets.

The revenue contract for the Barking power plant expired on September 30, 2010. A new tolling contract for 178 MW (ATCO Power's share 45 MW) of the plant's capacity was entered into for a one-year term commencing October 1, 2010. The remaining 822 MW of the plant's capacity (ATCO Power's share 210 MW) was sold into the merchant market commencing October 2010. A substantial portion of the U.K. electricity market is comprised of vertically integrated companies whose operations include both generation and supply. Market participants trade primarily through structured bilateral contracts and wholesale markets, with smaller volumes traded on a power exchange. Approximately 40% of the electricity generated is supplied from natural gas-fired generating plants. Changes in the U.K. market electricity prices may have an impact on the Corporation's earnings and cash flow from operations in the future.

ATCO Power has financed the majority of its non-regulated electrical generating capacity on a non-recourse basis. In these projects, the lender's recourse in the event of default is limited to the business and assets of the project in question, which includes the Corporation's equity therein. Canadian Utilities has

provided a number of guarantees related to ATCO Power's and ATCO Resources' obligations under their respective non-recourse loans associated with certain of their projects. ATCO Power (80%) and ATCO Resources (20%) have a joint venture in the Canadian projects subject to guarantees, excluding McMahon. ATCO Ltd. has indemnified and agreed to reimburse Canadian Utilities for any amounts it may be required to pay under these guarantees in respect of ATCO Resources' 20% interest. ATCO Ltd.'s indemnification to reimburse Canadian Utilities for any amounts payable under ATCO Resources 20% interest was cancelled effective January 1, 2011, when ATCO Resources was transferred to ATCO Power (refer to Company Overview – Internal Transfer of Subsidiaries section). The guarantees outstanding at December 31, 2010, are described in Note 12 to the consolidated financial statements. To date, Canadian Utilities has not been required to make any payments related to its guaranteed obligations.

The Corporation's generating plants are exposed to operational risks which may cause outages due to such issues as boiler, turbine, and generator failures. In order to mitigate this risk, a proactive maintenance program is carried out on a regular basis with scheduled outages for major overhauls and other maintenance issues. In addition, the Corporation carries property and business interruption insurance to protect against the risk of extended outages.

ATCO Midstream

ATCO Midstream is exposed to the difference between the selling prices of the NGL produced and the purchase price of shrinkage gas. Earnings from ATCO Midstream's NGL extraction operations will increase or decrease as the difference between the selling price of NGL and the purchase price of shrinkage gas increases or decreases.

ATCO Midstream is exposed to seasonal natural gas price differentials. The earnings and cash flow from natural gas storage operations will vary as the differences between the price of natural gas in the summer and the following winter fluctuate.

At ATCO Midstream's NGL facilities, the Corporation contracts commercial arrangements with pipeline shippers who hold NGL extraction rights on those pipelines delivering gas to the NGL facilities. In June 2007, the AUC initiated an industry-wide review of NGL extraction rights. On February 4, 2009, a decision was issued with respect to NOVA's natural gas transmission system that, in most cases, proposes to transfer ownership of the NGL extraction rights to the receipt point shippers (generally producers) from the border delivery shippers (generally exporters from the province who include ATCO Midstream's suppliers). NOVA has confirmed that it is committed to the NGL Extraction Convention application and has indicated a filing date in the second quarter of 2011. With anticipated hearing and transition timelines, full implementation would likely not occur before November 2013. The earnings and cash flow impact on certain of ATCO Midstream's NGL extraction facilities is uncertain at this time.

ATCO I-Tek

The Utilities purchase information technology services from ATCO I-Tek. ATCO Electric and ATCO Gas also purchase customer care and billing services from ATCO I-Tek. The recovery of these costs in customer rates is subject to AUC approval. In 2009, the Utilities completed a review of three options for the future provision of information technology and customer care and billing services. The options are (i) the repatriation of these services back into the Utilities; (ii) moving to a third party service provider; or (iii) renewing with ATCO I-Tek, the current service provider. Remaining with ATCO I-Tek was determined to be the least expensive option and the recommendation that the Utilities submitted to the AUC. A decision from the AUC is expected in 2012 on this recommendation.

Derivative Financial Instruments

In conducting its business, the Corporation uses various instruments, including forward contracts, swaps and options, to manage the risks arising from fluctuations in exchange rates, interest rates and commodity prices. All such instruments are used only to manage risk and not for trading purposes. For details on the financial instruments in place at December 31, 2010, see Note 22 to the consolidated financial statements.

The Canadian Institute of Chartered Accountants (CICA) recommendations require the recognition and measurement of derivative instruments embedded in host contracts that were issued, acquired or substantively modified on or after January 1, 2003. Derivative instruments embedded in host contracts that were issued, acquired or substantively modified prior to January 1, 2003, have not been identified and recognized in the consolidated financial statements as permitted by the recommendations.

The Corporation designates each derivative instrument as either a hedging instrument or a non-hedge derivative.

(a) A hedging instrument is designated as either:
   (i) a fair value hedge of a recognized asset or liability or,
   (ii) a cash flow hedge of either:
      - a specific firm commitment or anticipated transaction or,
      - the variable future cash flows arising from a recognized asset or liability.

At inception of a hedge, the Corporation documents the relationship between the hedging instrument and the hedged item, including the method of assessing retrospective and prospective hedge effectiveness. At the end of each period, the Corporation assesses whether the hedging instrument has been highly effective in offsetting changes in fair values or cash flows of the hedged item and measures the amount of any hedge ineffectiveness. The Corporation also assesses whether the hedging instrument is expected to be highly effective in the future.

A hedging instrument is recorded on the consolidated balance sheet at fair value. Payments or receipts on a hedging instrument that is determined to be highly effective as a hedge are recognized concurrently with, and in the same financial category as, the hedged item. Subsequent changes in the fair value of a fair value hedge are recognized in earnings concurrently with the hedged item. For a cash flow hedge, the effective portion of changes in fair value is recognized in other comprehensive income and is subsequently transferred to earnings concurrently with the hedged item, whereas the portion of the changes in fair value that is not effective at offsetting the hedged exposure is recognized in earnings.

If a hedging instrument ceases to be highly effective as a hedge, is de-designated as a hedging instrument or is settled prior to maturity, then the Corporation ceases hedge accounting prospectively for that instrument; for a cash flow hedge, the gain or loss deferred to that date remains in accumulated other comprehensive income and is transferred to earnings concurrently with the hedged item. Subsequent changes in the fair value of that derivative instrument are recognized in earnings.

If the hedged item is sold, extinguished or matures prior to the termination of the related hedging instrument, or if it is probable that an anticipated transaction will not occur in the originally specified time frame, then the gain or loss deferred to that date for the related hedging instrument is immediately transferred from accumulated other comprehensive income to earnings.

Hedge gains or losses that were recognized in other comprehensive income are added to the initial carrying amount of a non-financial asset or non-financial liability when:

(i) an anticipated transaction for a non-financial asset or non-financial liability becomes a specific firm commitment for which fair value hedge accounting is applied or,

(ii) a cash flow hedge of an anticipated transaction subsequently results in the recognition of the non-financial asset or non-financial liability.

(b) A non-hedge derivative instrument is recorded on the consolidated balance sheet at fair value and subsequent changes in fair value are recorded in earnings.

The Corporation applies settlement date accounting to the purchases and sales of financial assets. Settlement date accounting implies the recognition of an asset on the day it is received by the Corporation and the recognition of the disposal of an asset on the day that it is delivered by the Corporation. Any gain or loss on disposal is also recognized on that day.

Transaction costs that are directly attributable to the acquisition or issue of financial assets or financial liabilities that are not held for trading are added to the fair value of such assets or liabilities at the time of initial recognition.

Transactions with Related Parties

On January 1, 2011, the Corporation and its parent, ATCO Ltd., finalized the internal transfer of ATCO Resources to ATCO Power. For a more detailed description of this transaction, refer to Company Overview – Internal Transfers of Subsidiaries section.

In other transactions with ATCO Ltd. and its subsidiary corporations, the Corporation sold fuel in the amount of $1.4 million (2009 - $1.5 million), provided computer operations and systems development services totaling $5.0 million (2009 - $3.9 million), recovered administrative expenses totaling $2.4 million (2009 - $7.8 million) and incurred administrative expenses and corporate signature rights totaling $9.5 million (2009 - $8.8 million).

In transactions with entities related through common control, the Corporation incurred advertising, promotion and administrative expenses totaling $1.1 million (2009 – $1.4 million).

At December 31, 2010, accounts receivable due from related parties amounted to $7.0 million (2009 - $3.8 million) and accounts payable due to related parties amounted to $4.6 million (2009 - $3.5 million).

Except for the transfer of ATCO Resources, these transactions are in the normal course of business and under normal commercial terms, measured at the exchange amount.

Off-Balance Sheet Arrangements

The Corporation does not have any off-balance sheet arrangements that have, or are reasonably likely to have, a current or future effect on the results of operations or financial condition, including, without limitation, such considerations as liquidity and capital resources.

Contingencies

The Corporation is party to a number of disputes and lawsuits in the normal course of business. The Corporation believes that the ultimate liability arising from these matters will have no material impact on the consolidated financial statements.

Critical Accounting Estimates

The preparation of the Corporation's consolidated financial statements in accordance with GAAP requires management to make judgments, estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the year. On an on-going basis, management reviews its estimates, particularly those related to depreciation and amortization methods, useful lives and impairment of long-lived assets, amortization of deferred availability incentives, asset retirement obligations, employee future benefits and the fair value of financial instruments, using currently available information. Changes in facts and circumstances may result in revised estimates, and actual results could differ from those estimates. The Corporation's critical accounting estimates are discussed below.

DEFERRED AVAILABILITY INCENTIVES

ATCO Power is subject to an incentive/penalty regime related to generating unit availability of the Battle River and Sheerness generating plants. The amount to be amortized is dependent upon estimates of future generating unit availability and future electricity prices over the term of the PPAs. Each quarter, management uses these estimates to forecast high case, low case and most likely scenarios for the incentives to be received from, less penalties to be paid to, the PPA counterparties. These forecasts are added to the accumulated unamortized deferred availability incentives outstanding at the end of the quarter; the resulting total is divided by the remaining term of the PPAs to arrive at the amortization for the quarter. As at December 31, 2010, the Corporation had recorded \$48.2 million of deferred availability incentives. The amortization of deferred availability incentives recorded in revenues amounted to \$14.1 million in 2010.

Compared to the most likely scenario recorded in revenues for the year, the high case scenario would have resulted in higher revenues of approximately \$3.3 million, whereas the low case scenario would have resulted in lower revenues of approximately \$4.2 million.

EMPLOYEE FUTURE BENEFITS

The expected long term rate of return on pension plan assets is determined at the beginning of the year on the basis of the high quality long bond yield rate plus an equity and management premium that reflects the plan asset mix. A premium of 0.6% was added to the high quality long bond yield rate of 6.4%, resulting in an expected long term rate of return of 7.0% for 2010. This methodology is supported by actuarial guidance on long term asset return assumptions for the Corporation's defined benefit pension plans, taking into account asset class returns, normal equity risk premiums, asset diversification effect on portfolio returns and a recent change in the Corporation's portfolio asset mix policy.

Expected return on plan assets for the year is calculated by applying the expected long term rate of return to the market related value of plan assets, which is the average of the market value of plan assets at the end of the preceding three years. The expected long term rate of return declined to 7.0% in the year ended December 31, 2010. The result has been a decrease in the expected return on plan assets and a corresponding increase in the cost of pension benefits. In addition, the actual return on plan assets over the preceding three years has been lower than expected (i.e., an experience loss), which is also contributing to an increase in the cost of pension benefits as losses are amortized to earnings.

Accrued benefit obligations at the end of the year are determined using a discount rate that reflects market interest rates that match the timing and amount of expected benefit payments. The liability discount rate has also declined to 5.6% at the end of 2010. The result is an increase in benefit obligations (i.e., an experience loss), which contributes to an increase in the cost of pension benefits as losses are amortized to earnings.

In accordance with the Corporation's accounting policy to amortize cumulative experience gains and losses in excess of 10% of the greater of the accrued benefit obligations or the market value of plan assets, the Corporation is amortizing a portion of the net cumulative experience losses on plan assets and accrued benefit obligations over the expected average remaining service life of employees.

The assumed annual health care cost trend rate increases used in measuring the accumulated post employment benefit obligations in the year ended December 31, 2010, are as follows: for drug costs, 6.4% starting in 2010 grading down over 14 years to 4.5%, and for other medical and dental costs, 4.5% and 4.0%, respectively, for 2010 and thereafter. Combined with lower recent claims experience, the effect of these changes has been to decrease the costs of other post employment benefits.

The effect of changes in these estimates and assumptions is mitigated by an AUC decision to record the costs of employee future benefits when paid rather than accrued. Accordingly, the regulated operations, excluding ATCO Power, recognize a regulatory asset or liability equal to the amount that would otherwise be recorded as expense or income.

The sensitivities of key assumptions used in measuring accrued benefit obligations and benefit plan cost for 2010 are outlined in the following table. The sensitivities of each key assumption have been calculated independently of changes in other key assumptions. Actual experience may result in changes in a number of assumptions simultaneously.

	2010 Pension Benefit Plans		2010 Other Post Employment Benefit Plans	
($ millions)	Accrued Benefit Obligation	Benefit Plan Cost	Accrued Benefit Obligation	Benefit Plan Cost
Expected long term rate of return on plan assets				
1% increase [(1)]	-	(3.2)	-	-
1% decrease [(1)]	-	3.2	-	-
Liability discount rate				
1% increase [(1)]	(57.6)	(4.6)	(2.4)	(0.3)
1% decrease [(1)]	71.4	5.3	2.9	0.1
Future compensation rate				
1% increase [(1)]	11.8	1.5	-	-
1% decrease [(1)]	(11.3)	(1.5)	-	-
Long term inflation rate				
1% increase [(1)] [(2)] [(3)]	42.7	5.1	2.2	0.2
1% decrease [(1)] [(3)]	(48.9)	(5.9)	(1.9)	(0.3)

Notes:

(1) *Sensitivities are net of the associated regulatory asset (liability) and unrecognized defined benefit plans cost, which reflect an AUC decision to record costs of employee future benefits in the regulated operations, excluding ATCO Power, when paid rather than accrued.*

(2) *The long term inflation rate for pension plans reflects the fact that pension plan benefit payments are indexed to increases in the Canadian Consumer Price Index to a maximum increase of 3.0% per annum.*

(3) *The long term inflation rate for other post employment benefit plans is the assumed annual health care cost trend rate described in the weighted average assumptions.*

Changes in Accounting Policies

FUTURE ACCOUNTING CHANGES

International Financial Reporting Standards

The Corporation will begin reporting under International Financial Reporting Standards (IFRS) in the first quarter of 2011 with comparative data for the prior year. IFRS uses a conceptual framework similar to Canadian GAAP, but there are significant differences in recognition, measurement and disclosures.

On October 1, 2010, the Canadian Accounting Standards Board issued guidance to permit, but not require, entities with rate regulated activities to defer the transition to IFRS for one year, to 2012. The Corporation has decided to adopt IFRS effective January 1, 2011, and not to take the one year deferral for the following reasons:

- Adopting IFRS allows comparability to other non-regulated entities that will be adopting IFRS in 2011.
- Comparability to other regulated entities, whether or not they choose to take the one year deferral, will be accomplished by showing the impacts of rate regulated accounting as previously permitted by Canadian GAAP as an Adjusted Earnings item in the segmented note to the consolidated financial statements and in the MD&A.
- The International Accounting Standards Board (IASB) has concluded that it could not resolve the matter of accounting for rate regulated activities quickly and decided to develop a proposal for consideration for its future agenda in 2011. Therefore, waiting an additional year to adopt IFRS may not result in any greater clarity with respect to rate regulated accounting.

IFRS Conversion Project Status

The Corporation has established a Steering Committee, a project team, and working groups to review the adoption of IFRS. The project team and working groups provide position papers and regular updates to management, the Steering Committee and the Audit Committee. Education sessions have been, and will continue to be, provided for employees, senior management and the Audit Committee to increase knowledge and awareness of IFRS and its impacts.

The Corporation completed the Assessment and Diagnostic and Design and Planning phases of its IFRS Conversion Project in 2009 and is currently completing the Implementation and Review phase. The Implementation and Review phase involves making changes to accounting policies and procedures and financial information systems and training staff on the implementation of the new standards. Financial information in accordance with IFRS was collected in 2010 to allow for comparative reporting in 2011. The Corporation has completed the necessary changes to its financial reporting computer systems.

Position papers on issue-specific accounting differences between Canadian GAAP and IFRS and the impact on financial reporting computer systems are complete and they have been discussed with the Corporation's external auditor. The IASB's work plan includes a number of the IFRS standards that have been analyzed in the position papers. The position papers will be updated to reflect any changes resulting from final standards or directives issued by the IASB.

The Corporation has completed its review of the impact of IFRS on financial covenants. This review will be updated for changes in standards. Based on the work performed to date, the Corporation believes it will be in compliance with its financial covenants using IFRS financial information.

The Corporation has evaluated the impact of IFRS on internal control over financial reporting (ICFR) and disclosure controls and procedures (DC&P). The Corporation has not identified any changes that would

individually or in aggregate materially affect, or are reasonably likely to materially affect, its ICFR or DC&P.

Rate Regulated Accounting

On July 23, 2009, the IASB issued an exposure draft on rate regulated activities (the Exposure Draft). Subsequently, the IASB staff issued a summary of their analysis of the responses to the Exposure Draft. The IASB discussed various IASB staff papers in July 2010 and again in September 2010, but did not reach a conclusion on the recognition of assets and liabilities subject to rate regulation. The IASB has indicated that it will evaluate future steps for the rate regulated activities project following the public consultation on its future agenda.

In the absence of a rate regulated activities standard, the Corporation will not recognize regulatory assets and liabilities. As a result, there will be a reduction to assets of approximately $470 million, a reduction to liabilities of approximately $620 million and an increase to equity of approximately $150 million on transition to IFRS.

The absence of the recognition of regulatory deferral accounts will result in increased volatility in earnings. The Corporation is unable to predict the amount of the change because that will depend upon the nature of the decisions received from the AUC. The Corporation will disclose the impacts of rate regulation, as previously prepared under Canadian GAAP, as an Adjusted Earnings item in the segmented note to the financial statements and in the MD&A. It is the Corporation's belief that earnings adjusted for rate regulated accounting is a better reflection of the economics of rate regulation. In addition, this presentation will provide comparability to the Corporation's peer companies that have taken the one year deferral permitted by the Canadian Accounting Standards Board.

Significant Accounting Differences between Canadian GAAP and IFRS

The Corporation has identified that the following areas have the greatest potential impact on the Corporation's accounting: leases, employee benefits and regulatory assets and liabilities.

Leases

The Corporation is party to a number of project contracts that IFRS requires be reassessed to determine if they are to be accounted for as deemed leases. The Corporation's assessment is that several contracts will be deemed to be finance leases under IFRS with the Corporation as the lessor. Lease treatment was not required under Canadian GAAP as the contracts were entered into prior to the effective date of the Canadian GAAP standard.

For those arrangements deemed to be finance leases under IFRS, the project property, plant and equipment will be derecognized and a finance lease receivable measured as the present value of the lease payments to be received over the remaining life of the arrangement will be recognized. Payments received from the customer are allocated between interest income classified as revenue and principal payment based on a mortgage style calculation. The transition to IFRS will result in an increase to finance lease receivable of approximately $355 million and corresponding adjustments to Property, Plant and Equipment and Other Assets, and a reduction of approximately $12 million to Retained Earnings on the Consolidated Balance Sheet.

Employee Benefits

Employee benefits consist of pensions and other retirement benefits, including life insurance and medical care. Under Canadian GAAP, the Corporation amortizes experience gains and losses and other adjustments in excess of 10% of the greater of the accrued benefit obligation or the market value of plan assets to earnings over the remaining average service life of employees. This method is known as the corridor approach.

IFRS allows an entity to recognize the experience gains and losses on plan assets and liabilities in a number of ways:

- recognize 100% of annual gains and losses directly in earnings;
- amortize cumulative unamortized gains and losses exceeding the greater of 10% of plan assets or liabilities over the estimated average remaining service life of employees; or
- recognize 100% of annual gains and losses directly in other comprehensive income and then transfer them directly to retained earnings. The Corporation will adopt this method. Other comprehensive income will be more volatile; the level of volatility will depend upon the gains or losses experienced.

Joint Arrangements

Under Canadian GAAP, the Corporation's numerous joint arrangements are accounted for using proportionate consolidation. Under proportionate accounting, the Corporation records its proportionate share of the assets, liabilities, revenues and expenses of the joint arrangement. Under the IFRS exposure draft on joint arrangements, if the joint arrangement (and not the Corporation) has indirect interests to share in the "net" common outcome expected to be generated from a group of underlying assets and liabilities under the joint control of all of the venturers, the Corporation would account for those joint arrangements using equity accounting and report the investment in joint venture on the balance sheet and equity earnings on the statement of earnings.

The IASB has not yet issued a new joint arrangements standard and its effective date will therefore be subsequent to the IFRS conversion date of January 1, 2011. The Corporation has adopted the option under the existing IFRS standard for Interests in Joint Ventures to account for jointly controlled entities using proportionate accounting. As a result, there will effectively be no change to the Corporation's financial results from the accounting for joint ventures under Canadian GAAP.

IFRS 1 Exemptions

IFRS 1 First-time Adoption of International Financial Reporting Standards ("IFRS 1") requires entities to prepare and present an opening balance sheet at the date of transition to IFRS. The transition date for the Corporation is January 1, 2010. The Corporation has evaluated the optional exemptions available under IFRS 1 and made determinations.

In general, IFRS requires an entity to comply with all of the accounting standards effective at the end of the first reporting period after adopting IFRS. This means restating accounting transactions as if the standards had been in place when the transactions occurred. The IFRS 1 exemptions give limited exemptions from retroactively applying the standards where the cost of complying with this requirement would be likely to exceed the benefits to users of financial statements. Significant exemptions for the Corporation are:

Description of IFRS 1 Exemption	**Project Status**
Business Combinations An entity may elect not to restate business combinations that occurred before the date of transition to IFRS.	The Corporation will adopt this exemption, thereby resulting in no changes to the accounting for prior business combinations.
Employee Benefits An entity may elect to recognize all cumulative actuarial gains and losses at the date of transition as an adjustment to retained earnings.	The Corporation will adopt this exemption. This will result in a reduction of defined pension plan assets of approximately \$125 million, non-controlling interests of approximately \$50 million, deferred income tax liability of approximately \$35 million and retained earnings of approximately \$100 million and an increase in retirement benefit obligation of approximately \$10 million on transition to IFRS.
Fair Value as Deemed Cost An entity may elect to measure items of property, plant and equipment at fair value at the date of transition to IFRS and use that fair value as deemed cost.	The Corporation will adopt this exemption. This will result in a reduction of approximately \$170 million to property, plant and equipment, approximately \$45 million to deferred income tax liabilities and approximately \$125 million to retained earnings on transition to IFRS.
Rate Regulated Property, Plant and Equipment An entity that is subject to rate regulation may elect to use the carrying amount of property, plant and equipment determined under previous GAAP as initial cost on transition to IFRS.	Except as indicated below, the Corporation will adopt this exemption, with the result that, except for the reclassification of customer contributions to other liabilities (see Financial Statement Reclassifications below), there will be no change in the Utilities' transitional balances for property, plant and equipment. The Corporation will not adopt this exemption for the regulated generating plants of ATCO Power which will result in a reduction of approximately \$100 million to property, plant and equipment, approximately \$25 million to deferred income tax liability and approximately \$75 million to retained earnings on transition to IFRS.

Description of IFRS 1 Exemption	Project Status
Cumulative Translation Differences For all of its foreign operations, an entity may elect to recognize its cumulative translation adjustments at the date of transition as an adjustment to retained earnings.	The Corporation will adopt this exemption, thereby resulting in a decrease to retained earnings of approximately $50 million on transition to IFRS.
Decommissioning Liabilities – Asset Retirement Obligations An entity may elect to estimate the amount that would have been included in the cost of the related asset when the liability first arose by discounting the liability back to that date and calculating the accumulated depreciation at the transition date using the current estimated useful life.	The Corporation will adopt this exemption resulting in a reduction of property, plant and equipment of approximately $10 million, an increase in provisions and other liabilities of approximately $15 million and $5 million, respectively, and a reduction in retained earnings of approximately $20 million on transition to IFRS.

Financial Statement Reclassifications

There are a number of reclassifications that will be required under IFRS. Significant reclassifications for the Corporation are:

Customer Contributions:

The Corporation obtains contributions from utility customers to construct assets in situations where it is not economic to provide service to those customers at the approved rate charged to other customers. Under Canadian GAAP, the contributions are deducted from property, plant and equipment and amortized over the life of the related asset. Under IFRS, this contribution will be accounted for as deferred revenue on the basis that there is no stand-alone value for utility customers who provide these contributions without ongoing service by the Corporation. The deferred revenue will be amortized over the life of the related asset. The transition to IFRS will result in an increase to assets and liabilities of approximately $880 million as unamortized customer contributions are reclassified from an offset to property, plant and equipment to other liabilities on the consolidated balance sheet.

Long Term Debt Due Within One Year:

Under Canadian GAAP, when the Corporation intended to refinance long term debt within one year on a long term basis and there was a written undertaking from an underwriter to act on the Corporation's behalf with respect thereto, or sufficient capacity existed under long term bank loan agreements to issue commercial paper or assume bank loans, then long term debt due within one year was classified as long term. This treatment is not permitted under IFRS. The transition to IFRS will result in the reclassification of approximately $125 million of long term debt due within one year from long term liabilities to current liabilities.

Employee Benefits

Approximately $212 million will be reclassified to defined benefit assets from other assets and retirement benefit obligations, and approximately $60 million to retirement benefit obligations from other liabilities.

Provisions:

Under IFRS, provisions must be separately disclosed on the consolidated balance sheet. The transition to IFRS will result in the reclassification of approximately $80 million from deferred credits to provisions.

The provision for the power generation revenue contract liability, which under Canadian GAAP was shown separately as a liability, will not be recorded under IFRS. The options within the natural gas purchase contracts will be recorded at fair value as a derivative asset.

Nature vs. Function Presentation of the Statement of Earnings:

IFRS requires expenses on the statement of earnings to be classified either by nature or function, whereas Canadian GAAP allows a combination of the two. The Corporation has chosen to classify expenses on the statement of earnings according to their nature as salaries, wages and benefits, energy transmission and transportation, plant and equipment maintenance, fuel costs, manufacturing raw materials and consumables used and other expenses. The classifications operation and maintenance and selling and administration will no longer appear on the statement of earnings.

Quarterly Results of Operations

SELECTED INFORMATION

($ millions except per share data)	For the Three Months Ended [1] [2] [3] Mar. 31	Jun. 30	Sep. 30	Dec. 31	Total
2010					
Revenues	748.6	648.6	550.7	709.3	2,657.2
Earnings attributable to Class A and Class B Shares	148.0	76.2	82.2	128.6	435.0
Earnings per Class A and Class B Share	1.18	0.60	0.66	1.02	3.46
Diluted earnings per Class A and Class B Share	1.17	0.60	0.66	1.02	3.45
Adjusted Earnings [4]	152.0	76.3	82.0	130.6	440.9
Adjusted Earnings per Class A and Class B Share [4]	1.21	0.61	0.66	1.02	3.50
2009					
Revenues	768.6	602.7	537.1	675.6	2,584.0
Earnings attributable to Class A and Class B Shares	145.4	73.2	120.9	127.1	466.6
Earnings per Class A and Class B Share	1.16	0.58	0.96	1.01	3.71
Diluted earnings per Class A and Class B Share	1.16	0.58	0.96	1.01	3.71
Adjusted Earnings [4]	148.3	73.5	76.7	129.1	427.6
Adjusted Earnings per Class A and Class B Share [4]	1.18	0.59	0.61	1.02	3.40

Notes:

(1) *There were no discontinued operations or extraordinary items during these periods.*

(2) *Due to certain factors, revenues, earnings and Adjusted Earnings for any quarter are not necessarily indicative of operations on an annual basis. These factors include the seasonal nature of the Corporation's operations, changes in electricity prices in Alberta and the U.K., the timing and demand of natural gas storage capacity sold, changes in natural gas storage fees, changes in NGL prices and natural gas costs and the timing of rate decisions.*

(3) *The above data (other than Adjusted Earnings and Adjusted Earnings per Class A and Class B Share) has been extracted from the financial statements.*

(4) *Refer to Significant Non-Operating Financial Items section for a description of the adjustments made to earnings attributable to Class A and Class B Shares to obtain Adjusted Earnings.*

The principal factors that caused variations in financial condition and results of operations over the past eight quarters were:

- unplanned and planned outages affecting availability in ATCO Power's generating plants;
- the timing of utility rate decisions;
- fluctuations in natural gas prices, electricity prices and related Spark Spreads in Alberta and the U.K.;
- changes in market conditions in ATCO Midstream's NGL and storage operations;
- exchange rates;
- increase in rate base in the Utilities Segment;
- expiry of the Barking revenue contracts;
- Carbon Decisions;
- mark-to-market adjustments in ATCO Power;

- the impact of the ATCO Structures & Logistics Transaction
- H.R. Milner Income Tax Reassessment; and
- changes in share appreciation rights expense due to changes in the Corporation's Class A Share and ATCO Ltd.'s Class I Non-Voting Share prices.

Fourth Quarter 2010

All quarterly information in this document has been shaded to differentiate it from the annual information.

SEGMENTED INFORMATION

($ millions)	For the Three Months Ended December 31 Utilities	Energy	Corporate & Other	Intersegment Eliminations	Total
2010					
Revenue	**412.0**	**287.0**	**58.2**	**(47.9)**	**709.3**
Earnings attributable to Class A and Class B Shares	**71.5**	**44.1**	**13.3**	**(0.3)**	**128.6**
Mark-to-Market Adjustment [(1)]	**-**	**2.0**	**-**	**-**	**2.0**
Adjusted Earnings	**71.5**	**46.1**	**13.3**	**(0.3)**	**130.6**
2009					
Revenue	367.9	296.1	52.7	(41.1)	675.6
Earnings attributable to Class A and Class B Shares	52.8	72.5	1.7	0.1	127.1
Mark-to-Market Adjustment [(1)]	-	2.0	-	-	2.0
Adjusted Earnings	52.8	74.5	1.7	0.1	129.1

Note:

(1) *Refer to Significant Non-Operating Financial Items section for a description of the adjustments made to earnings attributable to Class A and Class B Shares to obtain Adjusted Earnings.*

Revenues for the three months ended December 31, 2010, **increased** by $33.7 million (5%) over 2009. This increase was primarily attributable to a $44.1 million (12%) increase in the Utilities Segment mainly due to increased rate base in ATCO Electric. This increase was partially offset by a decrease of $9.1 million (3%) in the Energy Segment due to lower Storage Price Differentials in ATCO Midstream and decreased revenues at ATCO Power's Barking generating plant due to the expiry of the revenue contract on September 30, 2010, offset by higher flow through natural gas sales and NGL prices in ATCO Midstream.

Adjusted Earnings for the three months ended December 31, 2010, **increased** by $1.5 million (1%) over 2009. This increase was primarily due to an $18.7 million (35%) increase in the Utilities Segment due to increased rate base in the Utilities and higher tax deductible costs associated with the capital program in ATCO Electric, and an $11.6 million (682%) increase in Corporate & Other mainly due to lower administrative expenses. These increases were partially offset by a $28.4 million (38%) decrease in the Energy Segment mainly due to lower Storage Price Differentials in ATCO Midstream and lower power prices and spark spreads in the U.K. electricity market in ATCO Power.

Alberta Power Pool electricity prices for the three months ended December 31, 2010, averaged $45.94 per MWh, compared to average prices of $46.27 per MWh in the corresponding period in 2009. Natural gas

prices for the three months ended December 31, 2010, averaged \$3.44 per GJ, compared to average prices of \$4.31 per GJ in the corresponding period in 2009. The consequence of these changes in electricity and natural gas prices was an average Spark Spread of \$20.17 per MWh for the three months ended December 31, 2010, compared to \$13.93 per MWh in the corresponding period in 2009.

U.K. power prices averaged £48.15 per MWh for the three months ended December 31, 2010, compared to average prices of £34.48 per MWh in the corresponding period of 2009. Natural gas prices averaged £4.93 per GJ for the three months ended December 31, 2010, compared to average prices of £2.56 per GJ in the corresponding period of 2009. Emissions allowance prices, which are traded in Euros, averaged £12.74 per tonne of CO_2 for the three months ended December 31, 2010, compared to average prices of £12.43 per tonne of CO_2 in the corresponding period of 2009. These electricity, natural gas and emissions allowance prices resulted in an average Spark Spread of £7.54 per MWh for the three months ended December 31, 2010, compared to an average Spark Spread of £11.02 per MWh in the corresponding period of 2009.

OTHER EXPENSES

($ millions)	For the Three Months Ended December 31		
	2010	2009	Change to 2010 (2010-2009)
Operating expenses:			
Natural gas supply	**51.4**	4.3	1,095%
Purchased power	**14.7**	14.3	3%
Operation and maintenance	**218.2**	233.5	(7%)
Selling and administrative	**80.6**	80.2	0%
Franchise fees	**46.8**	43.9	7%
	411.7	376.2	9%
Depreciation and amortization expenses	**82.4**	80.4	2%
Interest	**55.7**	60.7	(8%)
Income taxes	**32.9**	34.1	(4%)
Dividends on equity preferred shares	**11.1**	10.8	3%

Fourth quarter **operating expenses increased** by \$35.5 million (9%) over 2009. Natural gas supply expense increased due to higher flow through natural gas purchases in ATCO Midstream. Operation and maintenance expenses were lower due to lower fuel costs in ATCO Power's Alberta and U.K. generating plants, partially offset by higher line maintenance costs in ATCO Electric.

Interest expense for the three months ended December 31, 2010, **decreased** by \$5.0 million (8%) compared to 2009, primarily due to the redemption of \$125.0 million of CU Inc. 11.40% debentures on August 15, 2010. These debentures were not refinanced until the November 18, 2010 issuance of \$125.0 million of CU Inc. 4.947% debentures. Also contributing to the decrease in interest expense was the repayment of non-recourse long term debt in ATCO Power.

LIQUIDITY AND CAPITAL RESOURCES

SUMMARY OF CASH FLOW

($ millions)	For the Three Months Ended December 31 **2010**	2009	Change to 2010 (2010-2009)
Cash position, beginning of period	**456.8**	983.8	(54%)
Cash provided by (used in):			
Operating activities:			
Funds Generated by Operations	**186.2**	229.1	(19%)
Changes in non-cash working capital	**4.2**	(65.9)	106%
Cash flow from operations	**190.4**	163.2	17%
Investing activities	**(236.0)**	(196.2)	(20%)
Financing activities	**134.0**	(153.4)	187%
Foreign currency impact on cash balances	**(5.6)**	(1.4)	(300%)
Cash position, end of period	**539.6**	796.0	(32%)

OPERATING ACTIVITIES

For the three months ended December 31, 2010, **Funds Generated by Operations decreased** by $42.9 million (19%) compared to 2009. This decrease was primarily due to decreases in non-current regulatory assets and liabilities in the Utilities which vary from quarter to quarter and are, therefore, not comparable or indicative of funds generated by operations on an annual basis. For the three months ended December 31, 2010, **changes in non-cash working capital** were $4.2 million, an **increase** of $70.1 million (106%) compared to the corresponding period in 2009. This increase was primarily due to increased accounts payable in ATCO Electric due to higher payments owing to customers for the settlement of one time regulatory items in 2009, and lower accounts receivable resulting from reduced natural gas storage and flow through gas sales in ATCO Midstream.

INVESTING ACTIVITIES

Cash used in investing activities in the fourth quarter **increased** by 20% compared to 2009, primarily as a result of higher capital expenditures on regulated transmission and distribution projects in ATCO Electric and changes in non-cash working capital due to increased payments to ATCO Electric's capital program suppliers.

Capital expenditures were essentially unchanged at $270.4 million compared to $273.7 million in 2009.

FINANCING ACTIVITIES

In the fourth quarter, the Corporation had **net debt increases** of $107.8 million. **Issuance** of debt comprised of $125.0 million of 4.947% Debentures due November 18, 2050. **Redemptions** included $2.3 million of other long term debt and $14.9 million of non-recourse long term debt.

On December 2, 2010, CU Inc., a wholly owned subsidiary of the Corporation, **issued** $75.0 million of 3.80% Cumulative Redeemable Preferred Shares Series 4.

In the fourth quarter of 2010, there were **purchases** of $1.7 million of Class A Shares under the Corporation's normal course issuer bid, compared to nil in 2009. In the fourth quarter, **issues** of Class A Shares due to stock option exercises amounted to $3.6 million, compared to $3.7 million in 2009. **Net issues** were $1.9 million in 2010, compared to $3.7 million in 2009.

In the fourth quarter, total **dividends paid to Class A and Class B Share owners increased** by 7% to $47.5 million over the same period in 2009. In the fourth quarter, the **quarterly dividend** payment on the Corporation's Class A and Class B Shares **increased** by $0.025 to $0.3775 per share.

FOREIGN CURRENCY TRANSLATION

Foreign currency translation decreased the Corporation's cash position by $5.6 million due to changes in U.K. and Australian exchange rates used for balance sheet translations.

CANADIAN UTILITIES LIMITED

Consolidated Five-Year Financial Summary

(Millions of Canadian dollars, except as indicated)		2010	2009	2008	2007	2006
EARNINGS						
Revenues		**2,657.2**	2,584.0	2,778.9	2,404.9	2,430.4
Operating expenses		**1,557.1**	1,465.0	1,635.5	1,401.6	1,390.7
Depreciation and amortization		**335.5**	329.7	387.2	355.3	348.9
Interest		**235.9**	241.6	233.5	217.4	222.9
Gain on ATCO Structures & Logistics transaction		**-**	(33.9)	-	-	-
Earnings from investment in ATCO Structures & Logistics		**(19.7)**	(7.8)	-	-	-
Interest and other income		**(39.3)**	(43.3)	(59.1)	(64.3)	(58.5)
Income taxes		**109.2**	125.4	134.8	76.7	167.0
Dividends on equity preferred shares		**43.5**	40.7	32.5	34.3	35.8
Earnings attributable to Class A and Class B shares		**435.0**	466.6	414.5	383.9	323.6
Adjusted Earnings [1]		**440.9**	427.6	403.2	341.0	320.5
SEGMENTED EARNINGS						
Utilities		**244.6**	195.4	148.6	138.2	120.0
Energy		**150.7**	209.5	223.0	203.0	181.6
Corporate & Other and eliminations		**39.7**	61.7	42.9	42.7	22.0
Earnings attributable to Class A and Class B shares		**435.0**	466.6	414.5	383.9	323.6
BALANCE SHEET						
Cash [2]		**539.6**	796.0	726.6	747.2	798.8
Property, plant and equipment and intangibles		**7,295.4**	6,974.5	6,216.9	5,684.8	5,432.0
Total assets		**9,415.3**	9,083.6	7,860.0	7,299.7	6,990.9
Capitalization:						
Long term debt		**3,060.3**	3,102.3	2,844.3	2,603.2	2,411.5
Non-recourse long term debt		**302.8**	354.8	412.4	478.1	626.7
Equity preferred shares		**860.0**	785.0	625.0	625.0	636.5
Share owners' equity [3]		**3,275.2**	3,046.1	2,748.5	2,517.1	2,322.9
Total capitalization		**7,498.3**	7,288.2	6,630.2	6,223.4	5,997.6
CASH FLOWS						
Funds Generated by Operations [4]		**738.2**	793.4	796.5	688.6	641.0
Capital expenditures [5]		**869.0**	946.1	1,010.9	700.8	567.7
Financing (excluding Class A and Class B dividends)		**(42.3)**	374.1	179.9	56.5	45.1
Class A and Class B dividends		**190.0**	177.1	166.8	156.8	176.7
CLASS A & B SHARES						
Shares outstanding at end of year [3] (thousands)		**125,930**	125,860	125,510	125,295	125,388
Return on equity [3] [6] (%)		**13.8**	16.1	15.7	15.9	14.2
Earnings per share [3] ($)		**3.46**	3.71	3.30	3.06	2.57
Adjusted Earnings per share [1] [3] ($)		**3.50**	3.40	3.21	2.72	2.54
Dividends paid per share [3] [7] ($)		**1.51**	1.41	1.33	1.25	1.40
Equity per share [3] ($)		**26.01**	24.20	21.90	20.09	18.53
Stock market record - Class A non-voting shares ($)	High	**55.62**	45.20	51.80	55.00	48.94
	Low	**41.69**	34.05	33.11	41.83	35.15
	Close	**54.40**	43.75	40.50	46.40	47.73
Stock market record - Class B common shares ($)	High	**55.44**	44.50	51.75	54.00	48.85
	Low	**41.55**	34.00	33.04	42.00	35.72
	Close	**54.13**	43.77	40.00	46.00	47.66

(1) Adjusted Earnings are defined as earnings attributable to Class A and Class B shares after adjustments for items that are not in the normal course of business nor a result of day to day operations. This measure is not defined by Generally Accepted Accounting Principles and may not be comparable to similar measures used by other companies.

(2) Cash is defined as cash and short-term investments less bank indebtedness.

(3) Includes Class A non-voting shares and Class B common shares.

(4) Funds Generated by Operations is defined as cash generated from operations before changes in non-cash working capital. This measure is not defined by Generally Accepted Accounting Principles and may not be comparable to similar measures used by other companies.

(5) Includes purchases of property, plant and equipment and intangibles.

(6) Return on Equity is determined on the basis of earnings attributable to Class A and Class B shares divided by weighted average share owners' equity for the year.

(7) Dividends paid per share include a Special Dividend of $0.25 paid to Class A and Class B share owners on September 1, 2006.

CU

Consolidated Five-Year Operating Summary

(Millions of Canadian dollars, except as indicated)	**2010**	2009	2008	2007	2006
Utilities					
Natural gas distribution operations					
Capital expenditures [(1)]	**194.5**	189.6	249.7	191.6	167.4
Pipelines (thousands of kilometres)	**38.0**	37.7	37.2	36.5	35.9
Maximum daily demand (terajoules)	**2,169**	2,184	2,130	1,819	1,861
Natural gas distributed (petajoules)	**237**	250	238	233	219
Average annual use per residential customer (gigajoules)	**120**	121	124	127	126
Customers at year-end (thousands)	**1,057.4**	1,037.4	1,022.2	1,001.8	969.9
Electric distribution and transmission operations					
Capital expenditures [(1)]	**511.5**	497.8	518.4	311.8	238.1
Power lines (thousands of kilometres)	**73.0**	72.1	71.5	70.9	70.1
Electricity distributed (millions of kilowatt hours)	**10,532**	10,431	10,594	10,744	10,286
Average annual use per residential customer (kWh)	**7,555**	7,671	7,666	7,690	7,495
Customers at year-end (thousands)	**237.2**	233.1	228.2	223.0	216.3
Natural gas transmission operations					
Capital expenditures [(1)]	**82.9**	87.7	81.7	87.1	97.7
Pipelines (thousands of kilometres)	**8.5**	8.4	8.4	8.4	8.4
Contract demand for pipelines system access (terajoules/day)	**4,757**	4,877	5,034	5,143	5,032
Energy					
Capital expenditures [(1)]	**67.1**	151.5	109.7	56.7	54.0
Generating capacity operated (megawatts)	**4,957**	4,885	4,885	4,840	4,840
Generating capacity owned (megawatts)	**2,582**	2,503	2,503	2,467	2,474
Availability (%)	**92.5**	94.9	93.5	91.6	93.0
Natural gas processed (Mmcf/day)	**401**	401	435	478	480
Natural gas gathering lines (kilometres)	**1,075**	1,000	1,000	1,000	1,000

[(1)] Includes purchases of property, plant and equipment and intangibles.

GENERAL INFORMATION

INCORPORATION
Canadian Utilities Limited was incorporated under the laws of Canada on May 18, 1927 and was continued under the Canada Business Corporations Act by Articles of Continuance on August 15, 1979.

ANNUAL MEETING
The Annual Meeting of Share Owners will be held at 10:00 a.m., Thursday, May 5, 2011 at The Fairmont Hotel Macdonald, 10065 – 100th Street, Edmonton, Alberta.

AUDITORS
PricewaterhouseCoopers LLP
Calgary, Alberta

COUNSEL
Bennett Jones LLP
Calgary, Alberta

TRANSFER AGENT AND REGISTRAR
Class A non-voting and
Class B common shares and
Second Preferred
(Series W and X) Shares
CIBC Mellon Trust Company
Calgary/Montreal/Toronto/Vancouver

TRUSTEE, TRANSFER AGENT AND REGISTRAR
Debentures
BNY Trust Company of Canada
Calgary/Toronto

STOCK EXCHANGE LISTINGS
Class A non-voting Symbol CU
Class B common Symbol CU.X
Cumulative Redeemable Second
Preferred Shares
5.80% Series W Symbol CU.PR.A
6.00% Series X Symbol CU.PR.B
Listing: The Toronto Stock Exchange

ATCO GROUP ANNUAL REPORTS
Annual Reports to Share Owners and Financial Information (Consolidated Financial Statements & Management's Discussion and Analysis) for Canadian Utilities Limited and its parent company, ATCO Ltd., are available upon request from:

ATCO Ltd. & Canadian Utilities Limited
Corporate Office
1400, 909 – 11th Avenue SW
Calgary, Alberta T2R 1N6

Telephone: (403) 292-7500
Website: www.canadian-utilities.com
www.atco.com

SHARE OWNER INQUIRIES
Dividend information and other inquiries concerning shares should be directed to:

CIBC Mellon Trust Company
P.O. Box 7010
Adelaide Street Postal Station
Toronto, Ontario
Canada M5C 2W9

Telephone: 1-800-387-0825
Outside of North America: +1 (416) 643-5500
Fax: (416) 643-5501
Website: www.cibcmellon.com

BNY Trust Company of Canada
600 The Dome Tower
333 – 7th Avenue SW
Calgary, Alberta
Canada T2P 2Z1

Telephone: 1-800-254-2826

Printed in Canada

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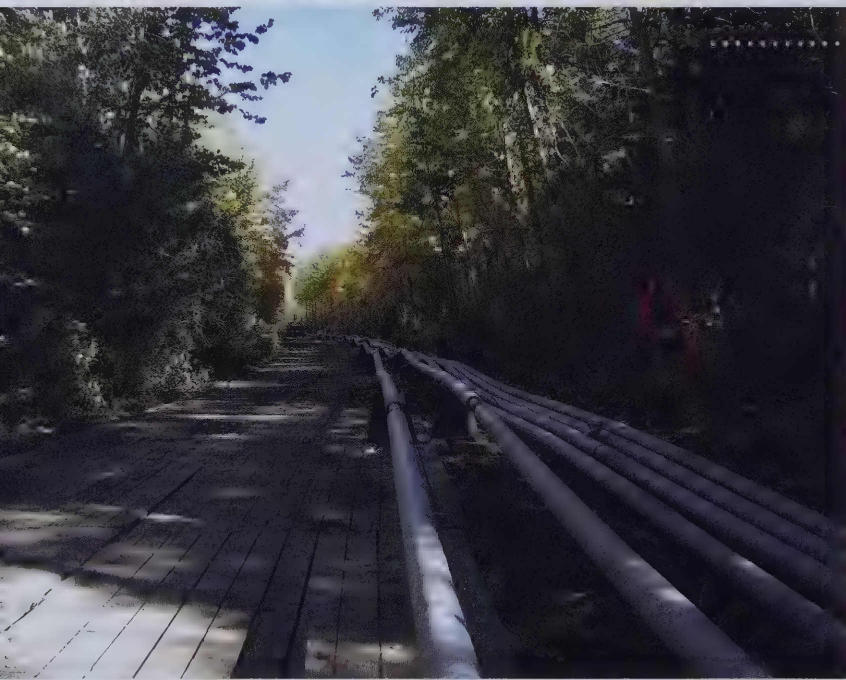
An ATCO Company

Canadian Utilities Limited Annual Report 2010



Canadian Utilities Quickfacts 2010

- In 1980, a 58.1 per cent controlling interest in Canadian Utilities Limited was acquired by ATCO Ltd. from IU International of Philadelphia. ATCO repatriated the company back to Canada
- Canadian Utilities has assets of approximately $9 billion
- Canadian Utilities employs more than 5,700 people
- Canadian Utilities' dividends per share increased in 2010 for the 38th consecutive year
- More than 40 per cent of Canadian Utilities' employees own shares in the company
- Significant growth potential led to the launch of ATCO Australia, providing integrated energy solutions from one company

Top: The ATCO Gas North Edmonton Operations Centre, which uses natural gas-powered geothermal heating and cooling technology.

Middle: ATCO Pipelines uses wooden rig mats to protect the ground and vegetation in its right-of-ways and prevent potential damage during construction.

Bottom: ATCO's 180 MW Osborne natural gas power cogeneration plant in Adelaide, Australia.

Canadian Utilities Limited 2010 Annual Report

Contents

Cover photo
ATCO Electric's Northwest Transmission Development Project. Construction of Phase 1, a 226 km, 240 kV line from Britnell to Wesley Creek between Peace River and Wabasca, Alberta

Canadian Utilities Limited is a diversified Canadian-based, international group of companies focused on profitable sustainable growth and achievement with approximately $9 billion in assets and more than 5,700 people actively engaged in Utilities (pipelines, natural gas and electricity transmission and distribution), Energy (power generation, natural gas gathering, processing, storage and liquids extraction) and Technologies (business systems solutions).

Utilities

ATCO Electric
ATCO Gas
ATCO Pipelines

Energy

ATCO Power
ATCO Midstream

ATCO I-Tek

Canadian Utilities Limited Financial Highlights

Consolidated Annual Results

(Millions of Canadian dollars except per share data)	Year End December 31 2010	2009
FINANCIAL		
Revenues	**2,657.2**	2,584.0
Earnings attributable to Class A & Class B shares	**435.0**	466.6
Adjusted earnings	**440.9**	427.6
Total assets	**9,415.3**	9,083.6
Class A & Class B share owners' equity	**3,275.2**	3,046.1
Funds generated by operations	**738.2**	793.4
Capital expenditures	**869.0**	946.1
CLASS A NON-VOTING & CLASS B COMMON SHARE DATA		
Earnings per share	**3.46**	3.71
Diluted earnings per share	**3.45**	3.71
Adjusted earnings per share	**3.50**	3.40
Dividends paid per share	**1.51**	1.41
Equity per share	**26.01**	24.20
Shares outstanding (thousands)	**125,930**	125,860
Weighted average shares outstanding (thousands)	**125,851**	125,637

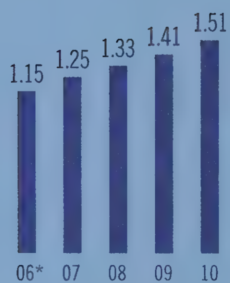
The above data (other than adjusted earnings, funds generated by operations, adjusted earnings per share and equity per share) has been extracted from financial statements which have been prepared in accordance with Generally Accepted Accounting Principles and the reporting currency is the Canadian dollar.

For further information, please see Canadian Utilities Limited Consolidated Financial Statements and Management's Discussion and Analysis - www.sedar.com.

Forward-looking Information:

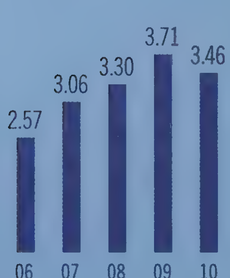
Certain statements contained in this Annual Report constitute forward-looking information. Forward-looking information is often, but not always, identified by the use of words such as "anticipate", "plan", "estimate", "expect", "may", "will", "intend", "should", and similar expressions. Forward-looking information involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information. The Corporation believes that the expections reflected in forward-looking information are reasonable, but no assurance can be given that these expectations will prove to be correct and such forward-looking information should not be unduly relied upon.

Nancy C. Southern
Deputy Chair, President & Chief Executive Officer



Dividends Per Share ($)

*excludes $0.25 special dividends



Earnings Per Share ($)

Assets ($ Billions)

President's Letter to Share Owners

Dear Share Owners:

Canadian Utilities' (CU) financial and operating performance in 2010 reflects the successful efforts of the 5,700 extraordinary and talented people of your company.

I have no doubt that you, like myself, will experience great pride as you read through the highlights and stories of our people working around the world to deliver our customers and communities products and services they can count on.

2010 was characterized by a very fragile global economy against a backdrop of continued regulatory and policy shifts, the re-emergence of a North American gas bubble and an abundance of power supply in Alberta, which had a significant impact on ATCO Midstream and ATCO Power, respectively.

However, the diversity of the businesses within our enterprise – 'the Piston Effect' as we've referred to it in the past - allowed us to overcome the challenges we faced.

CU's strong earnings of $435 million were supported by a robust balance sheet holding $540 million of cash and an industry leading 'A' credit rating.

These results were achieved through the strength and determination of our people, a deeply embedded focus on operational excellence with its inherent cost controls, and careful consideration of the environmental and social impact of our actions; now and for the future.

2010 marked the first full year of results from the 2009 amalgamation of ATCO Structures, ATCO Frontec and ATCO Noise Management, into ATCO Structures & Logistics,

in which CU has a 24.5 per cent ownership interest. The company grew its businesses worldwide securing new contracts and customers in Peru, Chile, Afghanistan, Australia, and throughout North America.

ATCO Structures & Logistics now offers complete infrastructure solutions to military and civilian customers worldwide, including workforce housing, innovative modular facilities, construction, site support services, logistics support, operations management, catering and noise reduction technologies.

Our rapid deployment capabilities were called to the forefront in earthquake-devastated Haiti, where we are helping to rebuild the infrastructure for government and social institutions to help the country and its people get back on their feet. ATCO Structures & Logistics also responded to the needs of the San Jose miners and their families in Chile with modular units placed at the mine site as the world watched the successful rescue of the 33 men.

In April 2010, during the Directors and Officers Strategy Conference, your Board of Directors approved an Australian growth strategy modeled after CU's existing Canadian enterprise of diverse yet complementary businesses to support the development of natural resources. CU already has a significant presence throughout Australia with many future opportunities identified as well as the successful commissioning of an environmentally advanced gas-fired generating facility in Karratha, Western Australia on April 9, 2010.

In January 2011, we launched a new company – ATCO Australia – focused on originating, developing, owning and operating energy infrastructure projects, drawing upon the expertise of ATCO Power, ATCO Pipelines, ATCO Gas, ATCO Midstream, ATCO Electric and ATCO Structures & Logistics.

In Alberta, ATCO Electric is advancing the Eastern Alberta Direct Current Transmission Line in accordance with the 2008 Government of Alberta Provincial Energy Strategy. The 500 kilovolt direct current transmission line will allow Albertans to harness wind and clean hydroelectric power as our coal-fired plants are decommissioned in the future to reduce our emissions footprint.

We have undertaken a comprehensive and exhaustive public consultation initiative to find a route along the less populated east side of the province as we strive to establish the route with the least impact on people, the land and the environment. More than 6,500 people have been consulted and we continue to listen attentively as the project moves toward permitting and construction. The capital investment is estimated to be $1.6 billion, the majority of which will occur between 2012 and 2014 with commissioning in 2014.

To ensure we have the right people and controls for the Eastern Alberta Direct Current Transmission Line as well as our $0.8 billion Hanna Region Transmission Development Project, we have reorganized ATCO Electric into a Capital Division and an Operations Group, led by Presidents Sett Policicchio and Bobbi Lambright, respectively.

We are also working closely and collaboratively with governments to address climate change issues, now that the federal Minister of the Environment has set preliminary parameters for eliminating traditional coal-fired generation.

As the federal government moves forward with CO_2 regulations, CU remains confident that a strong and robust electrical grid will deliver unmatched economic and environmental benefits to Canada. Supporting our vision is our belief that we must continue to invest in our collective future to ensure reliability and competitive access to renewable and sustainable electricity, such as hydroelectric projects on the Slave and Athabasca rivers.

In summary, it was a challenging yet rewarding year. I want to thank my colleagues in the Office of the Chairman, the executive teams in our operating companies, and the 5,700 men and women of CU without whom our success in 2010 would not have been achieved. Their commitment to finding new ways to better serve our customers is the essence of the ATCO 'Heart and Mind' and your company's true advantage.

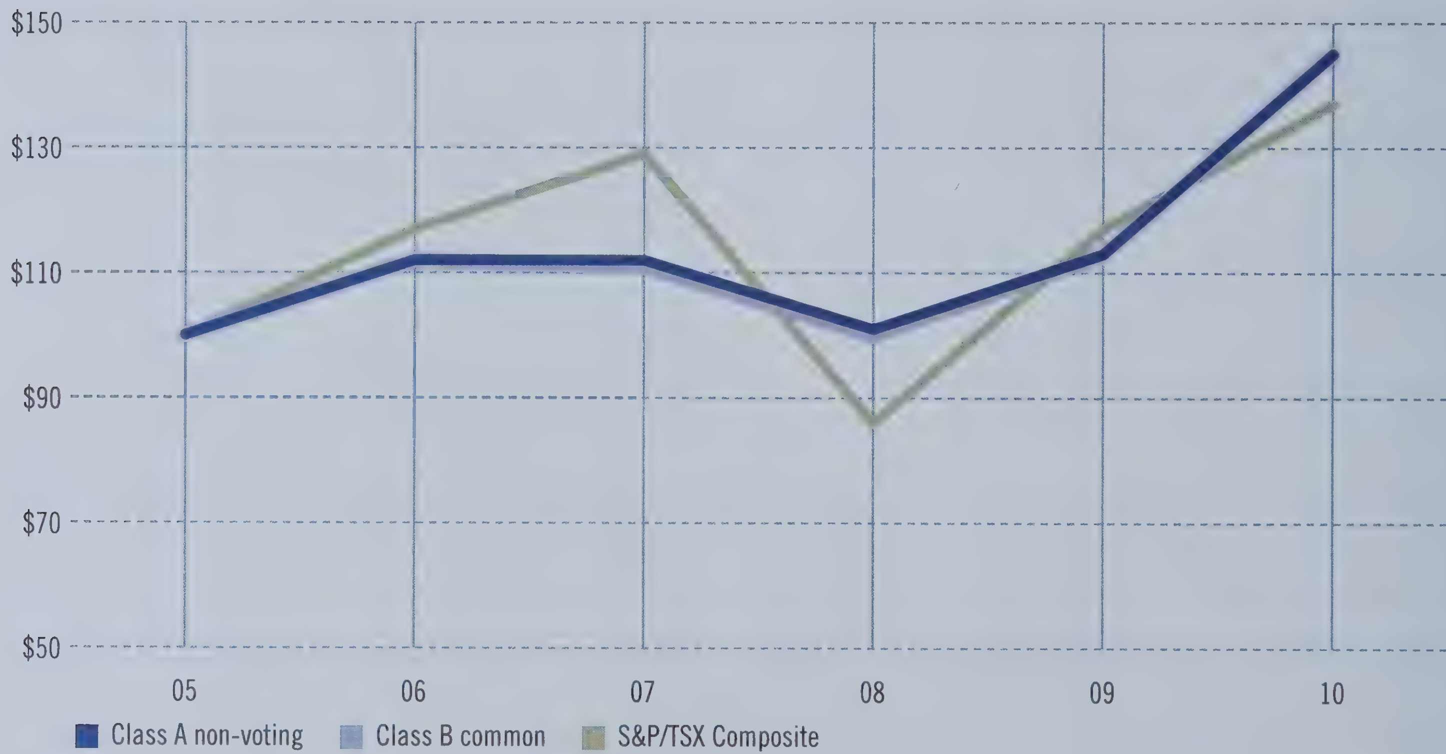
I also wish to express my deepest appreciation to our Board of Directors who so generously provide their wisdom and counsel and who are at the very heart of our accomplishments.

Warmest regards,

N. C. Southern
Deputy Chair, President
& Chief Executive Officer

Five-Year Total Return on $100 Investment

Canadian Utilities Limited Class A Non-Voting and Class B Common Shares



CU Compound Growth Chart	Compound Growth Rate	Cumulative Return
Class A non-voting	7.7%	$145
Class B common	7.7%	$145
S&P/TSX Composite	6.5%	$137

The graph compares the cumulative share owner return over the last five years on the Class A non-voting and Class B common shares of the Corporation (assuming reinvestment of dividends) with the cumulative total return of the S&P/TSX composite index.

Canadian Utilities Limited Share Ownership

It is important for prospective owners to understand that Canadian Utilities Limited is a diversified group of companies principally controlled by ATCO Ltd., which in turn is principally controlled by Sentgraf, a Southern family holding company.

It is also important for present and prospective share owners to understand that the Canadian Utilities share registry has both non-voting and voting common shares.

Chairman's Letter

Ronald D. Southern
Chairman of the Board

To Our Share Owners,

Your President's report highlights a year of notable achievements in 2010, and on behalf of my colleague Directors, and the owners of our shares, I would like to compliment and thank all of the people who make up our Canadian Utilities enterprises for a job truly well done.

It has been a busy year for Directors as well, for they have provided an enhanced focus to our global, national and sectorial strategies and tactics.

On the subject of governance, I must tell you how impressed I am with the quality of our Board's discussions and the results of the mix of management's and Directors' combined talent, knowledge, experience and standards brought to you by this remarkable group of men and women who work to deliver excellence for your company. This dedication results in commitments which go far beyond that shown in job descriptions, or time formally logged for board and committee meetings.

Our decision to preemptively take all of our Principal Operating Subsidiaries and consolidations to IFRS accounting in 2011 is well-documented in this report. I commend your review of this as well as our long-standing share ownership statement.

Looking to 2011 and beyond, we believe the world is in for a long period of adjustment. Yet, because we believe there is an inexorable shift of manufacturing to the emerging nations who require large and reliable sources of resources, our plans for the future allow for our reasoned growth and participation in the markets we have chosen.

Our Australian strategy seems to us to be logical and achievable steps for growing from the great base of attention we bring to our Canadian and American operations.

We have the people and financial resources to do this, giving us a considered confidence of meaningful success for our five-year plans … step by step … year by year. The markets being targeted by your management are best described as resource development infrastructure in Canada, U.S.A., Australia and South America where we can deliver the ATCO integrated model of long-standing proven infrastructure products and services to our customers of: electric power generation, electrical transmission; pipelines; midstream facilities; storage caverns; and structures and logistics.

Other possibilities may occur of course, but your management is very conscious of maintaining a supreme focus as called for in their plans.

Still, it will not be easy. For while, perhaps, it is a sweeping generalization, it has been said: "The only thing we learn from history is that men never seem to learn from history." Your Officers and Directors bear this in mind as we proceed, for who amongst us can explain the rebirth of "global risk taking" in most nations little more than a year after the financial crisis with all its negative ramifications of 2009/2010.

When your Directors and Officers look at the situation, we summarize these risks in economic terms as:

- macroeconomic risks
- emerging market risks
- market liquidity risks
- credit risks
- monetary and financial risks

All of which, with varying implications, will be exacerbated if world economies and their populations are subjected to significantly higher interest rates. We have considered these to the best of our ability.

As we move through these tremendous times with the swift succession of formidable events, I am deeply impressed with your Company's great leadership capacity, in thought and action, to not only seize the wide ranging opportunities presented to us, but also their ability to master difficulties and turn them into opportunities as well.

This capability will serve us well in the years ahead.

Your Company, Canadian Utilities, has increased your dividend for 38 consecutive years, and the value created for the investment you may have made in 1972 is 14 per cent compounded annual return. Looking at it another way, had you invested $100 in 1972 and reinvested all your dividends since 1972, your $100 original investment would now be worth $18,368.

Canadian Utilities' Share Registry has a tremendous base of Alberta owners. At 60 per cent, it surely is unique, and on behalf of the people in our companies (6,500 out of a total of 7,700) who are based in every village, town and city here in Alberta, I would like to thank, in the most genuine way possible, <u>all</u> of our share owners, who have invested their hard earned money with us for so many decades, for your confidence, spirit, and trust.

Respectfully submitted,

Ronald D. Southern
Chairman of the Board

Transmission in Alberta

Siegfried W. Kiefer
Managing Director, Utilities

Across North America, significant investment in new transmission capacity is required to ensure that reliable transmission infrastructure is in place ahead of power generation development and load growth. Significant lead times are required to ensure a reliable source of electricity when, and where it is needed. And as a wider mix of energy supply comes on stream – including from renewable sources such as hydro, wind and biomass – a long-haul transmission network that can carry energy efficiently from its production point, often in remote locations, to major population centres is imperative.

Such is the case in Alberta where economic growth is forecast to lead the nation in 2011. As industry and the province's population grows, so too will the growth in demand for electricity. Yet the province's electric grid – the "backbone" of the entire electric system – has not seen major new transmission lines built for more than two decades. As a result, the system is running close to capacity, resulting in restrictions on transmission maintenance activities and many situations where load restrictions are being considered as the next step to ensure reliability.

To meet the anticipated demand for electricity by Albertans, both reinforcement and expansion are needed. New transmission lines must be built in the province over the next decade. This will create certainty for business decisions that rely on electricity, such as new industrial investment, and allow new forms of generation investment to be made with confidence. Our transmission system needs to be appropriately sized to accommodate long-term growth and employ advanced technology, where possible, to maximize efficiency and minimize environmental impacts.

Given these circumstances, the Alberta Electric System Operator (the independent not-for-profit organization that plans and leads the operation of Alberta's interconnected power system) has directed ATCO Electric to prepare a facility application for the construction of a 500 kV high voltage direct current transmission line. The application was filed with the Alberta Utilities Commission in March 2011. The line will extend 500 km along the east side of the province on a carefully planned route that, after consultation with landowners, will have the least overall impact on people, agriculture, industry and the environment. Deemed "critical transmission infrastructure", this project will be among the first applications of direct current technology in Alberta and will be designed to serve Albertans for many decades to come.

Alberta's electricity supply mix is expected to change significantly as coal-fired plants are decommissioned and renewable energy supply is added. Canadian Utilities is working with government and industry on developing a framework to responsibly decommission coal-fired generation as Canada seeks to reduce greenhouse gas emissions.

While coal has been the mainstay of base load power generation in Alberta, Canadian Utilities continues to explore opportunities to leverage its experience and resources to develop new sources of sustainable energy and advance Canadian Utilities' vision for a "green corridor". New hydro generation in northern Alberta and Canada's North combined with a robust, safe, reliable, and economic transmission system, will provide clean, sustainable and abundant energy for the benefit of all Albertans for generations.

A 240 kV ATCO Electric transmission line near St. Paul, Alberta.

Utilities

The Utilities business segment includes ATCO Electric, ATCO Gas and ATCO Pipelines. These companies are focused on the safe, reliable and efficient transportation and distribution of natural gas and electricity.

ATCO Electric

- 38 offices throughout northern and east-central Alberta
- Serves approximately 211,000 customers in 245 communities in Alberta
- Operates and maintains more than 82,000 km of distribution and transmission power lines in Alberta
- Subsidiaries include Northland Utilities and Yukon Electrical

ATCO Gas

- More than 60 district offices across Alberta
- Serves more than one million customers in nearly 300 communities
- Owns and operates nearly 38,000 km of distribution pipeline
- Provides expert customer advice through ATCO EnergySense and ATCO Blue Flame Kitchen

ATCO Pipelines

- 217 natural gas transmission customers
- Delivers 3.8 billion cubic feet of natural gas per day to customers
- Owns and operates 8,486 km of pipeline
- Interconnections facilitate access to multiple intra-Alberta and export markets

Near Turner Valley, Alberta – ATCO Pipelines' reclamation standards will ensure that every project plan includes returning areas affected by construction activity to their original state.

As part of its Avian Protection Program, ATCO Electric worked with Alberta Fish & Wildlife to relocate an osprey nest near Fox Creek, Alberta.

ATCO Electric

ATCO Electric builds, operates and maintains a safe, reliable network of transmission and distribution power lines to homes, farms and businesses in cities, towns and Aboriginal communities across Alberta. The company serves almost 211,000 customers in 245 communities spanning 65 per cent of Alberta, with service areas in the northern and east-central areas of the province. These resource-rich areas play an essential role in Alberta's industrial development.

ATCO Electric has been serving this challenging, diverse territory for more than 80 years. It operates and maintains more than 82,000 km of transmission and distribution power lines including almost 12,000 km of distribution power lines on behalf of Rural Electrification Associations (REAs).

In 2009, ATCO Electric was authorized by the Government of Alberta to prepare a facility application to build and operate a new high-voltage transmission line along an eastern corridor in Alberta. The Eastern Alberta Direct Current Transmission Line will connect the Gibbons-Redwater area northeast of Edmonton to an area south of Brooks. The project is part of the Alberta Electric System Operator's (AESO) effort to build a robust transmission grid that meets growing needs and supports long-term economic growth in the province.

In 2010, ATCO Electric reorganized to more efficiently manage the largest capital program in its history. The reorganization also enables ATCO Electric to continue to maintain operational excellence and focus on strategic development opportunities.

ATCO Electric is now composed of the following three divisions:

- **Capital Projects Division** – responsible for all major transmission construction.
- **Operations Division** – responsible for managing the operation and maintenance of existing transmission, distribution and technology assets as well as large distribution construction.
- **Development Division** – responsible for key strategic initiatives and developing long-term growth for ATCO Electric and the North of 60 companies.

To further address the company's growth as well as a retiring workforce, ATCO Electric hired a record 350 new employees in 2010. That compares to 298 new people in 2009 and 250 in 2008.

Capital Growth

Provincial economic development and increasing customer demand continue to drive ATCO Electric's capital growth. In addition to the

Eastern Alberta Direct Current Transmission Line (see story on page 14), several other major capital projects moved forward in 2010.

In 2009, the AESO identified the need for new transmission facilities in the Hanna region to reinforce the current system and meet increased demand. The Hanna Region Transmission Development (HRTD) consists of adding new transmission lines and substations, upgrading existing substations and salvaging existing transmission lines and equipment.

Public consultation for HRTD began in March 2010, and is ongoing with landowners in key areas. Preferred routes for a large portion of the contiguous line have been identified, based on consultation feedback and other criteria. Several facilities applications were filed with the Alberta Utilities Commission and will continue in early 2011. Pending approval, construction on the major portion of the HRTD is proposed to begin in winter 2011.

Elsewhere in the province, the first and second phases of the Northwest Transmission Development Project were completed. Phase I – a 226 km, 240 kV line from Britnell to Wesley Creek between Peace River and Wabasca – was energized in 2009. Phase II – a 126 km, 240 kV line connecting the Wesley Creek area northeast of Peace River to the Meikle area northeast of Manning – was energized in late September, 2010. Responsible project management, greater access to materials and reduced labour costs resulted in cost savings of more than 40 per cent from the original budget estimate on Phase II of the project.

Multiple large-scale projects are also ongoing in Fort McMurray. Many are in response to continued economic growth in the region. Regional re-development projects, such as the widening of Highway 63 and the construction of a new bridge across the Athabasca River, require the removal, relocation and, in one instance, burial of several kilometres of line. The work promises to enhance electricity reliability for the rapidly growing region.

Operational Excellence

Customer service and outage response continue to benefit from new technology and improved processes. The Central Work Desk, created to enhance operational efficiency and outage response, celebrated its first year of operation. The team was put to the test during unprecedented spring storm activity in southeast Alberta. They handled more than 17,000 outage calls as a result of the spring storm.

New technology was piloted to better manage power outages. The system interfaces with automatic meter reading technology to quickly estimate the outage location and relay the information to field staff.

ATCO Electric continued its commitment to promoting public and employee safety. For its long-standing partnership with the Grande Prairie and Area Safe Communities organization, ATCO Electric was honoured with a business partner award.

Safe Communities organization is dedicated to promoting public safety in the Grande Prairie region. ATCO Electric sponsors several of its initiatives and local employees volunteer on its board.

The Farm Safety Campaign reduced the number of contacts between high-load farm equipment and overhead lines. The campaign encouraged farmers to plan ahead and let ATCO Electric help them move large equipment.

To improve employee safety while working alone, a new system was piloted to provide employees in remote and rural locations with centralized monitoring support. Monitoring units were piloted in Stettler, Grande Prairie and at isolated generation sites.

In the area broadly identified on this map, ATCO Electric serves all customers, with the exception of a small number of farm customers served by two self-operating rural electrification associations.

ATCO Electric hosted 14 open houses in June and July to share details about the Eastern Alberta Direct Current Transmission Line.

Eastern Alberta Direct Current Transmission Line

ATCO Electric was authorized to prepare a facility application to build and operate a 500 kilovolt (kV) direct current (DC) transmission line along an eastern corridor in Alberta. The Eastern Alberta DC Transmission Line will connect the Gibbons-Redwater area northeast of Edmonton to an area south of Brooks. It has been deemed Critical Transmission Infrastructure and is a key component of the Alberta Electric System Operator's (AESO) long-term plan to bolster the province's electricity transmission system.

Public consultation began in spring 2010. In June, detailed information packages outlining the preliminary route options were sent to 6,500 affected landowners and interested parties. More than 7,000 Albertans took time to provide valuable input on the project at open houses in the summer and in one-on-one consultations that continued through the fall of 2010. The feedback received was critical to ATCO Electric finding a route with the least overall impact on people, agriculture and the environment.

A province-wide media campaign including print, radio and television ads was launched in October to thank Albertans for their input and encourage them to continue to provide feedback.

The preferred route was determined in January 2011, at which time ATCO Electric continued to consult once more with affected landowners. Following a review of the feedback, a facility application was filed with the Alberta Utilities Commission in March 2011.

ATCO Electric has been recognized internationally for the quality of its public consultation and environmentally progressive practices in the development of a large transmission project. In 2004, ATCO Electric became the first Canadian company to win an Edison Award for its development of the Dover-to-Whitefish transmission line project.

ATCO Electric is the only electric utility in Alberta with experience in operating a DC facility. ATCO Electric owns and operates the McNeill DC converter station, which is required to interconnect the Alberta and Saskatchewan electrical systems as their system frequencies are not synchronized.

Direct current technology was selected by the AESO for the Eastern Alberta Direct Current Transmission Line project because it is typically used to transport bulk power over long distances. DC transmission lines transmit power more efficiently and require a smaller right-of-way than an alternating current transmission system of equivalent capacity.

The ATCO EnergySense Energy Education Mobile.

ATCO EnergySense

Established in 2001 by ATCO Gas and ATCO Electric, ATCO EnergySense provides Albertans with energy efficiency advice and improvement services for their homes and businesses.

In 2010, ATCO EnergySense handled more than 10,800 phone calls and emails requesting information on energy efficiency and energy assessments. The team completed more than 2,500 residential and commercial energy assessments.

In April, ATCO EnergySense launched the ATCO Energy Education Mobile – a travelling classroom designed to give students an opportunity to learn about the province's energy sources and energy efficiency in a fun, hands-on setting. The tallow-based biodiesel-fuelled travelling classroom was developed by ATCO EnergySense in consultation with Alberta teachers.

Topics covered are compatible with the Alberta Grade 4 Science and Social Studies curriculum. With the help of computers and interactive games, students learn to identify where the province's energy comes from and how to use it efficiently. With visits to more than 90 schools, plus special appearances at community events, more than 18,000 Albertans experienced the ATCO EnergySense Energy Education Mobile in 2010.

Energy Minister Ron Liepert and Canadian Utilities President & CEO Nancy Southern, along with Grade 4 students, learn about energy sources and energy conservation inside the ATCO Energy Education Mobile.

A Northland Utilities employee cleans frost off a line to ensure the power stays on.

Canadian Utilities in The North

For more than a century, Canadian Utilities (CU) has been building mutually beneficial relationships with northern partners. CU's numerous partnerships have created many successful businesses. CU is committed to the North and believes in supporting the communities where we live and work.

For CU companies operating North of 60, 2010 was a year of renewal – from utility franchise agreements to a renewed commitment to the environment and alternative technologies. It was also a year of new frontiers.

Northland Utilities

Northland Utilities has been lighting up the North for more than half a century. The company serves nine communities and the majority of customers in the Northwest Territories, including Yellowknife and Hay River. Northland Utilities is a full-service electrical company providing retail, distribution, transmission and generation services to its customers. The company has two operating divisions: Northland Utilities (NWT) Limited and Northland Utilities (Yellowknife) Limited.

Northland Utilities (Yellowknife)

In the Northwest Territories, Northland Utilities renewed its franchise agreement with the City of Yellowknife in 2010. The 10-year agreement underscored the city's confidence in ATCO to provide electrical service. Serving nearly 8,000 customers, Yellowknife is Northland Utilities' largest franchise in the NWT.

Last year, the company implemented automatic meter reading in the northern capital. This new system means Northland Utilities no longer has to enter people's yards or businesses to gather meter information. Instead, information is obtained more efficiently and accurately through mobile collectors.

At the same time, Northland Utilities successfully completed phase six of an eight-phase 25 kV conversion in Yellowknife. The program is taking substations and electrical feeders up to new standards. It will also reduce long-term operating and maintenance costs as well as provide additional long-term transmission capacity for Yellowknife load growth. There are multiple benefits to Northland Utilities (Yellowknife) customers, including a higher level of service reliability and a reduction in system losses. There is also a direct environmental benefit through reduced diesel fuel consumption for generation.

Canadian Utilities' Northern Service Area

Communities served by Yukon Electrical and Northland Utilities
138 kV Transmission Lines
Other Transmission Lines

Northland Utilities (NWT)

For almost 60 years, Northland Utilities has been serving communities in the North. The company provides electricity to approximately 2,700 customers in Trout Lake, Kakisa, Dory Point, Fort Providence, Wekweeti (formerly Snare Lake), Enterprise, Hay River and K'atl'Odeeche First Nation.

Two hundred kilometres north of Yellowknife, in Wekweeti, Northland Utilities (NWT) received a band council resolution to extend its franchise agreement with the community for another 10 years. Wekweeti is one of several remote communities that rely solely on Northland to both generate and distribute power. The community of Trout Lake has also issued a new 10-year resolution. These resolutions are yet another example of the good relationships Northland has with the northern communities it serves.

Yukon Electrical

For almost 110 years, The Yukon Electrical Company Limited has been providing electrical service to Yukoners. Chartered in 1901, the pioneer company began generating electricity for the residents of Whitehorse using a wood-fired, horizontal piston steam engine. Since then, Yukon Electrical has grown to serve almost 16,000 customers in 19 communities from south of the Yukon border to north of the Arctic Circle. The company's head office and service centre is in Whitehorse.

In 2010, Yukon Electrical focused on ways of reducing electrical demand and reliance on diesel fuel – with the customer in mind. The company is participating in a Demand Side Management program to work with customers in reducing electrical demand. Yukon Electrical installed 24 LED streetlights as a pilot project to evaluate their lower electrical consumption characteristics. In addition, a study of a combined wind-diesel generating system was carried out to evaluate the reduction of fuel consumption by using wind power. The company is also looking at adding incremental hydro capacity at its Fish Lake generating facility.

Inuvik Gas/ATCO Midstream

In the western Arctic, ATCO Midstream continues to grow its business. As a one-third partner in the Ikhil Joint Venture and Inuvik Gas, ATCO Midstream is focused on the production, gathering and processing of natural gas for the town of Inuvik, NWT. The gas originates from two wells at the Ikhil reservoir, located 50 km northwest of Inuvik. A pipeline transports a supply of natural gas for power generation, commercial and residential heating for the town of 3,500. 2010 marked the 11th anniversary of Inuvik Gas and 11 new commercial customers.

ATCO Energy Solutions/ATCO Gas

Straight south of Inuvik in Norman Wells, Canadian Utilities (CU) stepped up when the town of Norman Wells asked for assistance. Various CU companies helped the town through a gas supply outage in the summer. Under the coordination of ATCO Energy Solutions, an ATCO Gas team mobilized a propane-air distribution plant and operators from Calgary to Norman Wells to keep the town gas distribution system operating during the supply outage. The propane-air plant was staffed 24-hours-a-day for almost a month to ensure a safe and reliable gas supply to the town's distribution system. CU employees also undertook a number of maintenance and inspection activities to help the town assess the condition of the gas distribution system to ensure safe and reliable delivery of gas to its customers.

The North Edmonton Operations Centre uses natural gas-powered geothermal heating and cooling technology.

ATCO Gas

ATCO Gas builds, operates and maintains a safe, reliable, and cost-effective network of natural gas distribution pipelines of nearly 38,000 km and provides service to municipal, residential, business and industrial customers.

ATCO Gas is Alberta's largest natural gas distribution utility serving more than one million customers in nearly 300 Alberta communities.

In July, the City of Edmonton approved a 20-year renewal of the ATCO Gas franchise agreement to continue to provide natural gas distribution services to more than 250,000 customers in the city.

ATCO Gas has enjoyed a long history with Alberta's capital city having provided it with natural gas service since 1923. Edmonton and the capital region have the largest concentration of ATCO employees, and ATCO Gas continues to grow its business in the area.

An independent survey of Albertans in 2010 indicated that 94 per cent of customers had an overall favourable impression of ATCO Gas.

Responding to Growth

Economic growth in Alberta brought increased demand for ATCO Gas service. In total, nearly 20,000 new service connections were made. To better meet the growing needs of its customers, ATCO Gas opened two new operations centres and completed construction on a third.

To enhance service in the capital region, the North Edmonton Operations Centre (NEOC) officially opened in March. NEOC is the largest commercial building in Canada to use natural gas-powered geothermal heating, ventilating, and cooling technology. The facility uses 40 per cent less energy than similar-sized buildings. It is estimated to reduce carbon dioxide emissions by 60 metric tonnes annually. This achievement resulted in ATCO Gas becoming a finalist for an Alberta Emerald Foundation Award in 2010.

Construction on ATCO Gas's third natural gas-powered geothermal facility, the Airdrie Operations Centre, was completed in 2010.

In response to continued economic growth in northeast Alberta, ATCO Gas opened a new operations centre in Fort McMurray. The new facility was redesigned to better meet service demand for the rapidly growing Wood Buffalo region.

Major Gas Line Replacement Project

In September, the Blackfoot Trail mains project in Calgary wrapped up with the completion of its second phase. It was the largest capital project undertaken by ATCO Gas in 2010. Work involved replacing 16-inch diameter gas line mains with new 24-inch lines along a 16-block stretch of a major roadway in Calgary.

The project presented many unique challenges such as high traffic volume, possible disruption to businesses, railroad crossings, large intersections and proximity to other utilities. Special work processes were employed to ensure the work was done safely and with minimal disruption. The project was completed on time and under budget.

Natural Gas and Safety

ATCO Gas reinforced its commitment to public safety. The "Call Before You Dig" damage prevention program resulted in a continued reduction in the number of natural gas line hits. The annual public safety program is intended for contractors and homeowners. It promotes use of the Alberta One-Call free line-locate program to avoid hitting underground utility lines when excavating. In 2010, the number of line locates increased and the number of damages per 1,000 line locates was the lowest since 2004.

ATCO Gas also undertook a province-wide winter yard safety campaign to encourage homeowners to keep yards free of hazards and sidewalks shovelled to protect themselves and ATCO Gas employees from accidents.

A carbon monoxide safety campaign was also undertaken in 2010 to educate Albertans on how to detect and avoid carbon monoxide in the home.

Environmental Innovation

In only its third year in operation, the ATCO Gas Drake Landing solar project in Okotoks became the first solar community in the world to receive 80 per cent of its yearly space heating through solar energy.

Drake Landing is the largest subdivision of energy-efficient and environmentally responsible new single family homes in Canada. ATCO Gas has partnered with other organizations such as Alberta Environment, Sterling Homes and Climate Change Central to fund this one-of-a-kind community.

ATCO Gas operates one of the largest natural gas vehicle fleets in Alberta. More than 250 of its fleet vehicles are powered by the clean-burning fuel. This results in significant greenhouse gas reductions each year.

The Blackfoot Trail mains project in Calgary replaced gas lines along a 16-block stretch of a major roadway.

In the area broadly identified on this map, ATCO Gas serves the vast majority of communities as well as certain rural franchise areas.

ATCO Pipelines' Southern Extension project will be completed in 2011, bringing online 169 km of new transmission pipeline and facilities.

ATCO Pipelines

ATCO Pipelines has been an integral part of Alberta's provincial natural gas transmission system for almost a century, with peak delivery of 3.8 billion cubic feet per day. ATCO Pipelines' transportation customers can access the markets of their choice through the company's innovative, flexible and cost-effective transportation solutions.

ATCO Pipelines provides natural gas transportation services to producers, marketers, industrial customers and gas distribution companies in Alberta. It owns and operates more than 8,400 km of pipeline with approximately 4,100 receipt and delivery points.

These high-pressure pipelines and facilities are located throughout the province, covering both urban and rural areas. To ensure public safety and system reliability, ATCO Pipelines has comprehensive preventive maintenance and integrity programs in place. Methods used to test our facilities include a cross-section of practices, including: leak surveys, in-line inspections, cathodic protection surveys, visual inspections and capital improvements. The company's capital expenditures for pipeline upgrades and expansions was $83 million last year.

ATCO Pipelines – NGTL Operating Systems Integration

In 2010, ATCO Pipelines and TransCanada Corporation's wholly owned subsidiary, NOVA Gas Transmission Ltd. (NGTL), made significant progress toward the integration of their service and systems in Alberta. The companies received initial approvals from the Alberta Utilities Commission and the National Energy Board to proceed towards implementation of an initiative that would see integration of the companies' two separate operating systems, rates, and customer service within Alberta.

As a result of an agreement between the two companies in 2008, the arrangement would see the companies combine physical assets under a single rates and services structure, with a single commercial interface with customers, but with each company separately managing assets within distinct operating territories throughout the province. It is expected that the model will end duplicative tolling and operational activities and will result in more efficient regulatory processes.

As the two companies await the opinion of the federal Competition Bureau, they are working together in preparation of the next steps required to implement systems designed to improve service for all Alberta customers. Instead of competing for

customers, they will provide seamless natural gas transmission service to customers throughout the province. Pending approval, full implementation will be completed by mid-2012.

Pipeline Expansion and Upgrade Projects

In 2010, ATCO Pipelines undertook several significant pipeline projects to ensure reliability of service and meet customer demand.

The Inland Pipeline System project involved several upgrades to various valve assemblies along this major transmission pipeline that is vital for service to the Fort Saskatchewan and Edmonton markets. The improvements allow for the internal passage of an inspection device that will be used to detect any defects in the pipeline. The technology permits proactive repair of potential defects to ensure the long-term integrity of the pipeline.

With the Southern Extension project, which runs from Red Deer to Ryley, ATCO Pipelines is replacing 169 km of pipeline originally built in 1945–1946. The original pipeline has reached the end of its operational life and is being replaced with a new pipeline. The three-phase project commenced in 2008 and will be completed in 2011. In 2010, workers completed 71 km of replacement pipe, with the final 64 km scheduled for completion next year. The project involves close coordination with distribution companies as the pipeline serves hundreds of connections with these customers.

In Fort Saskatchewan, a major delivery station was commissioned by ATCO Pipelines for a large industrial customer. The customer requested 43,000 gigajoules per day of gas delivery from ATCO Pipelines for its upgrader expansion project. The station has many layers of redundancy built-in so that the failure of any single piece of equipment will not result in a station shut down. Creating safeguards to ensure sustainable operations was an important aspect of the design of this facility.

Last year, a new pipeline lateral to Stony Plain was installed to ensure security of supply to customers. To support growing core market demand in Stony Plain, ATCO Pipelines installed approximately seven km of pipeline to serve a new gate station on the north side of the community.

Advanced controls help reduce fuel usage

Enhanced engine controllers were installed at ATCO Pipelines' Cloverbar compressor station. The enhanced engine controllers regulate the ratio of air to fuel present during the combustion process of the compressor, leading to an improvement in the efficiency of the compressor station. The controllers will reduce ATCO Pipelines' carbon footprint by about 1,000 tonnes CO_2e per year, equivalent to taking approximately 180 cars off the road.

The ATCO Pipelines Control Centre in Edmonton where employees monitor ATCO's high-pressure natural gas system 24-hours-a-day, seven-days-a-week.

Urban Pipeline Renewal Project

Improving the safety and reliability of the high-pressure natural gas transmission systems in Alberta's two major urban centres of Calgary and Edmonton is a major initiative for ATCO Pipelines.

After extensive preparation in 2010, ATCO Pipelines is planning to create the equivalent of a ring road of high-pressure transmission pipelines away from the highly developed and populated areas where the pipelines are currently located. The existing pipelines were built more than four decades ago when the two major Alberta cities were much smaller. Over time, these pipelines have become surrounded by urban growth.

Construction on these pipelines is projected to start in 2011 and continue for five years. The new, larger pipelines will have additional capacity for growth and will be installed within existing utility corridors in the two cities. In Calgary, the Stoney Trail ring road is the main utility corridor while in Edmonton the corridor is Anthony Henday Drive.

Where required, the existing pipelines will be transferred to ATCO Gas to be used as infrastructure within its distribution system.

Energy

The Energy business segment includes ATCO Power and ATCO Midstream. These companies are engaged in power generation and natural gas gathering, processing, storage and liquids extraction.

ATCO Power

- Developer, construction manager, owner and operator of technologically advanced and environmentally progressive independent power generation plants
- Operated 19 power generation plants in Canada, the United Kingdom and Australia (now 16 plants with the launch of ATCO Australia-see page 27)
- 19 plants have combined capacity of approximately 5,000 MW, and a total ownership interest of about 57 per cent

ATCO Midstream

- Has ownership interest in 10 natural gas gathering and processing facilities and four natural gas liquids extraction facilities
- Processing capacity of 1.8 billion cubic feet per day
- Combined natural gas storage capacity of more than 40 billion cubic feet
- One-third interest in the Ikhil Joint Venture and Inuvik Gas, located in Inuvik, NWT

Karratha power generating station in Western Australia.

ATCO Power's Sheerness generating station, located near Hanna, Alberta. The turbine shaft is connected to an electrical generator to produce electricity.

ATCO Power

ATCO Power is a world-class developer, construction manager, owner and operator of technologically advanced and environmentally progressive independent power generation plants in Canada and select global markets.

With a combined capacity of approximately 5,000 megawatts (MW) (2,811 MW of which are owned directly by the company), ATCO Power in 2010 operated 19 generating facilities in Canada, the United Kingdom (U.K.) and Australia: 16 facilities fuelled by clean natural gas, one emissions-free hydroelectric facility and two coal-fired plants. [1]

Success in New Plant Construction

In June, ATCO Power celebrated the official opening of its Karratha power generating station in Western Australia. Constructed, owned and operated by ATCO, the 86 MW facility is the most efficient and environmentally friendly gas-fired generating station in the region. The generating station supplies electricity under a 20-year contract with state-owned Horizon Power.

Located in the resource-rich northwest quadrant of Western Australia, 1,600 km north of Perth, the Karratha power station was constructed using the world-class expertise of ATCO Power. It was built ahead of schedule, under budget and without a single lost-time incident. Karratha is ATCO's third generating station in Australia. [2]

Refocusing the Power Business

Due to the economic downturn, the generating industry is especially challenged in the U.K., where ATCO Power's long-term off-take contract expired in 2010, exposing the 1,000 MW Barking gas-fired generating facility to market prices. There is significant focus on Barking's long-term success as ATCO Power moves into a new era of U.K. operations.

1. *ATCO Power operated an additional 14 MW at the Heathrow Cogeneration Plant with EDF Energy plc through their joint venture company Thames Valley Power (TVP) until July 2010; upon contract expiry TVP sold the plant and equipment in the facility to the British Airport Authority.*

2. *Effective January 2011, the three Australian generating facilities of ATCO Power were transferred to ATCO Australia, a new CU subsidiary focused on pursuing opportunities in the country's energy sector* *(see page 27).*

ATCO Power's Worldwide Generation Facilities

12 POWER PLANTS IN ALBERTA

1 POWER PLANT IN BRITISH COLUMBIA

1 POWER PLANT IN SASKATCHEWAN

1 POWER PLANT IN ONTARIO

1 POWER PLANT IN UNITED KINGDOM

3 POWER PLANTS IN AUSTRALIA

2010 ATCO Power Generating Capacity

GENERATING CAPACITY (MW)	**4,957**
GENERATING CAPACITY OWNED (MW)	**2,811**

Canada

	Facility	Net Generating Capacity (megawatts)	Fuel Type
1	Battle River 3, 4 & 5	670 MW	Coal
2	Brighton Beach	580 MW	Natural Gas
3	Cory	260 MW	Natural Gas
4	Joffre	480 MW	Natural Gas
5	McMahon	120 MW	Natural Gas
6	Muskeg River	170 MW	Natural Gas
7	Oldman River	32 MW	Run-of-River Hydro
8	Poplar Hill	45 MW	Natural Gas
9	Primrose	85 MW	Natural Gas
10	Rainbow Lake 1, 2 & 3	88 MW	Natural Gas
11	Rainbow Lake 4 & 5	90 MW	Natural Gas
12	Scotford	170 MW	Natural Gas
13	Sheerness 1 & 2	760 MW	Coal
14	Sturgeon	18 MW	Natural Gas
15	Valleyview 1 & 2	90 MW	Natural Gas

United Kingdom

	Facility	Net Generating Capacity (megawatts)	Fuel Type
16	Barking	1,000 MW	Natural Gas

Australia

	Facility	Net Generating Capacity (megawatts)	Fuel Type
17	Bulwer Island	33 MW	Natural Gas
18	Karratha	86 MW	Natural Gas
19	Osborne	180 MW	Natural Gas


Battle River power station control room, located at Forestburg, Alberta.

Overall, 2010 was a challenging year for ATCO Power with low power pool prices, not only in the U.K., but in Alberta as well. However, ATCO Power has made significant debt repayments in recent years, which has positioned the company well to weather the current market conditions.

In addition, ATCO Power restructured to create a more streamlined organization focused on finding efficiencies in its base business while maintaining a high safety priority. Where possible, employees were redeployed to other ATCO companies to assist in the growth of those companies. ATCO Power also transferred in the assets of Alberta Power (2000) Ltd. from CU Inc. in October 2010, and ATCO Resources Ltd. from ATCO Ltd. in January 2011. These assets allow for clear ownership of CU's Canadian power generating plants and create efficiencies and simplification of administration and financial reporting.

Maintaining Quality and Safety Performance

Despite the challenges, ATCO Power maintained a strong focus on employee development, training, leadership and succession planning throughout the organization. As in previous years, safety remained the number one priority. Through the efforts of all its employees, the company achieved significant health and safety milestones, including receiving the 2009 Canadian Electrical Association President's Bronze Award of Excellence for Employee Safety in 2010. The Joffre, Muskeg River, and ATCO Power's smaller facilities in Alberta achieved 10 years without a lost-time incident. The company also introduced new office safety and safe driving policies and programs.

The company's ability to maintain safe, reliable operation while implementing effective cost controls was validated with benchmarking studies that confirmed the facilities studied (Battle River, Sheerness, Joffre and Brighton Beach generating stations) are operating very well relative to their industry peers.

Demonstrating Environmental, Industry and Community Leadership

CU is actively participating and consulting with the provincial and federal governments regarding the power generation industry's future. This consultation includes the development of greenhouse gas and other pollutant regulations as well as discussions regarding the future of coal-fired generation.

ATCO Power has established a team to review operations at its 670 MW Battle River coal-fired generating facility in Forestburg. The power purchase arrangements for two of the three units at the plant are set to expire at the end of 2013. The team is charged with studying all aspects related to the end of the power purchase arrangement, including potential options to keep the plant operational to continue to serve the needs of the province.

The Battle River and Sheerness stations installed and conducted testing on mercury capture equipment; this equipment came into service at the end of 2010 and is designed to capture more than 70 per cent of the mercury contained in the coal.

ATCO Power also maintained key community investment initiatives, especially in the area of education, where scholarships support the recruitment of power technology graduates needed to staff power generation plants in rural Alberta communities. The company demonstrated a commitment to support communities where employees work with donations to a community centre in Forestburg and a fire hall in Hanna.

ASHCOR Technologies

ASHCOR markets the coal combustion products from ATCO Power's coal-fired generating stations in Alberta. By collecting the fly ash produced and using it in new cementing materials, ASHCOR and its customers achieve two environmentally significant results: it captures a by-product that would normally go to a reclamation site and uses it in other construction material applications.

For every metric tonne of cement displaced by fly ash, approximately one metric tonne less of CO_2 is released into the atmosphere.

ATCO Australia's Osborne cogeneration/combined–cycle gas turbine power plant located in Adelaide, South Australia. The 180 MW plant is fuelled by natural gas.

ATCO Australia

Significant growth potential, coupled with Canadian Utilities' (CU) already strong presence in Australia, prompted the launch of ATCO Australia Pty Ltd in January 2011. The new company's headquarters are located in Perth. Its creation reinforces CU's belief in the strength of the Australian economy, particularly the resource-rich region of Western Australia.

ATCO Australia is headed up by Steven Landry in a newly established role of Managing Director & Chief Operating Officer. He oversees CU's power generation and energy infrastructure business in the country. ATCO Australia will focus on building greenfield and growing organic opportunities and, where it makes sense, consider acquisitions. Following the ATCO philosophy of develop, build, own and operate, ATCO Australia currently operates three power generation stations. The business development group is actively considering new opportunities.

ATCO Australia will provide a full range of energy services, drawing upon its existing expertise, including distribution of natural gas and electricity, and natural gas gathering, processing, storage and liquids extraction.

Based on the strength of mining, petroleum and liquefied natural gas (LNG) industries, there is an increasing demand for power, gas distribution, electricity, pipelines, midstream and workforce housing infrastructure. ATCO Australia will provide integrated energy solutions from one company.

ATCO's presence in Australia dates back to 1961 with the opening of a 70,000 sq. ft. modular building manufacturing plant in Adelaide. ATCO has experienced impressive growth in Australia during the past decade, first within ATCO Structures (now ATCO Structures & Logistics), followed by ATCO Power partnering in innovative power generation plants.

In June 2010, ATCO Power celebrated the opening of its environmentally friendly Karratha power generating station in the northwest quadrant of Western Australia. The 86 MW facility is the most efficient gas-fired generating station in the region. The company's other facilities include the 180 MW Osborne generating station in Adelaide and the 33 MW Bulwer Island cogeneration plant, part of the Queensland Clean Fuels Project that uses recycled water for its demineralization facility. All three Australian power plants are now part of ATCO Australia.

The Golden Spike Gas Plant, located west of Edmonton, Alberta, is part of the ATCO Midstream Integrated Gas System.

ATCO Midstream

ATCO Midstream provides natural gas gathering, processing, storage and liquids extraction to the Canadian natural gas sector. Focusing on its customers' needs, ATCO Midstream creates customized solutions and lasting customer relationships by drawing upon a proven track record and a partnership approach to business.

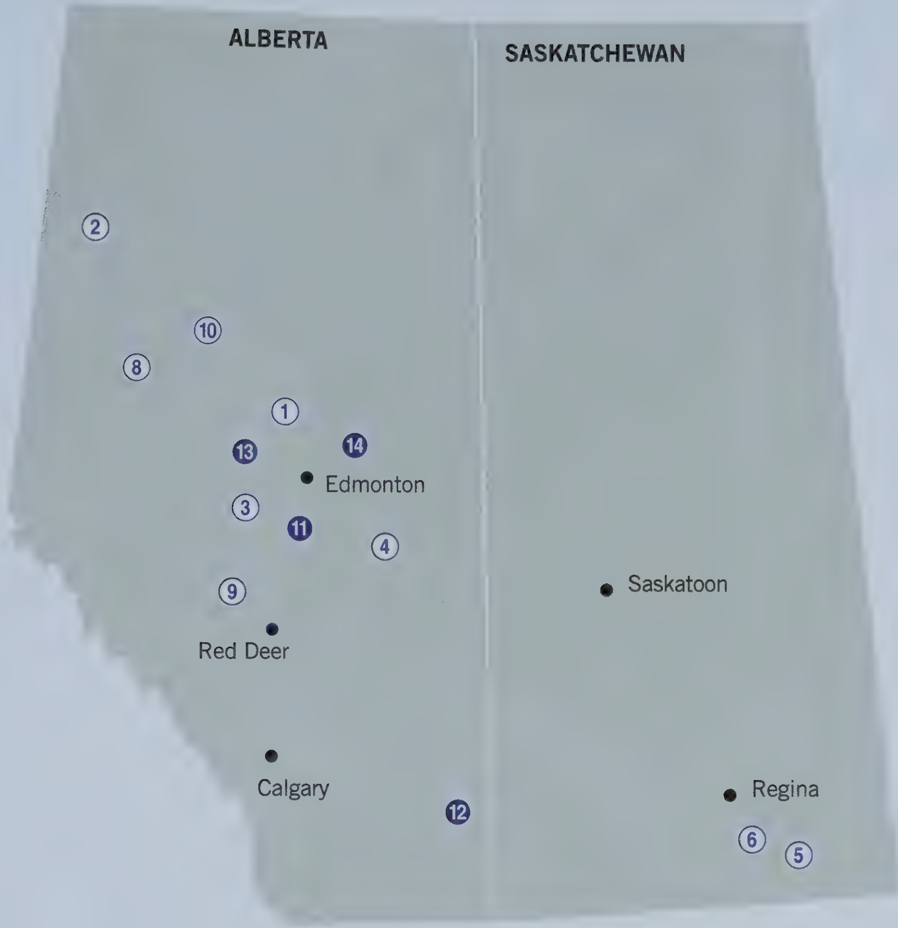
Since 1992, the company has played a significant role in the natural gas industry through its facilities in Alberta, Saskatchewan, Manitoba and the Northwest Territories. Assets include 10 natural gas gathering and processing facilities and four natural gas liquids extraction facilities. The company provides innovative natural gas storage services with more than 40 billion cubic feet of capacity available.

ATCO Midstream is active in Canada's North as a partner in the Inuvik Gas Project—the first natural gas development project north of the Arctic Circle.

In 2010, low natural gas prices caused by strong North American supply created a challenging environment for ATCO Midstream. The company benefited from higher frac spreads in its Natural Gas Liquids business unit despite lower cross-border flow, increased competitive pressures and increased transportation costs. The company was able to find additional value through the contracting of new gas volumes and enhanced natural gas liquids sales arrangements.

Low natural gas prices resulted in reduced drilling activity which impacted gas plant throughput in its Gas Gathering and Processing business unit. ATCO Midstream continues to seek solutions to consolidate gas plants and to lower unit processing costs to provide its customers with the most competitive operating costs possible. The effect of warmer than normal summer weather and strong gas supply reduced seasonal gas price volatility which affected storage differentials in the Storage and Energy Services business unit. Despite these challenges, the business unit was able to increase its customer base in 2010 by providing customer focused storage services.

Throughout the year, ATCO Midstream focused on cost reductions while maintaining plant availability at high levels. Initiatives focused on reducing power costs and optimizing the efficiency of existing plants so that the company could offer its customers competitive fees and had the added advantage of reduced environmental impact and lower emissions.



ATCO Midstream Facilities

- ○ Natural Gas Gathering Processing Facilities
- ● Gas Liquids Extraction Facilities

Facility	Licensed Capacity (mmcf/day)
1 Carbondale Gas Plant	56
2 Cranberry Gas Plant	36
3 Golden Spike Gas Plant	65
4 Kinsella Gathering and Compression Facility	20
5 Nottingham Gas Plant	18
6 Kisbey Gas Plant	5
7 Ikhil Gas Plant	8
8 Puskwaskau Gas Plant	21
9 Watelet Gas Plant	20
10 Widewater Gas Plant	12
11 Edmonton Ethane Extraction Plant	390
12 Empress Gas Liquids Straddle Plant	1,100
13 Villeneuve Ethane Extraction Plant	40
14 Fort Saskatchewan Ethane Extraction Plant	37

Facilities Expansion

In 2010, ATCO Midstream continued to expand its service offerings and geographical reach to customers in the Bakken Shale located in southeast Saskatchewan.

ATCO Midstream and SaskEnergy Inc. commissioned a major expansion project at the Kisbey Gas Plant. The $44 million project, funded jointly by SaskEnergy's Bayhurst Energy Services Corporation and ATCO Midstream, increased the capacity of the Kisbey Gas Plant to five million cubic feet of gas per day. It also extended the current gathering system by the addition of 48 km of gathering pipelines and two compressor stations. The expansion captures solution gas volumes and enhances producers' revenues while reducing greenhouse gas emissions. At its new capacity, the Kisbey Gas Plant is capable of removing up to 115,000 tonnes of greenhouse gases from the atmosphere each year. That's equivalent to the emissions produced by more than 17,000 homes.

People and Safety

A year after ATCO Midstream presented the first annual Medicine Hat College Power Engineering Scholarships, the company was able to hire the first two recipients as full-time operators at its Empress facility.

Health, safety, security and environment continue to be of paramount importance for ATCO Midstream. In 2010, nine facilities were honoured with awards from the Gas Processing Association Canada. These include:

- Carbondale Gas Plant
- Cranberry Gas Plant
- Empress Gas Liquids Straddle Plant
- Fort Saskatchewan Ethane Extraction Plant
- Golden Spike Gas Plant
- Kisbey Gas Plant
- Villeneuve Ethane Extraction Plant
- Watelet Gas Plant
- Widewater Gas Plant

One of two ATCO I-Tek Data Centres in Alberta.

ATCO I-Tek

ATCO I-Tek manages business-critical technology, applications and end-to-end business processes for a diverse group of clients that operate in Canada, the United States and around the world. Headquartered in Edmonton, it is a disciplined business-to-business service provider with proven processes and controls.

ATCO I-Tek provides application development and integration; workstation and customer support; server, network and security services; voice systems; infrastructure planning and implementation; and technical support. The company also provides reliable, large-scale retail energy and utility customer care and billing, managing approximately 2.5 million customer relationships in one of the most complex industry structures in North America.

As the high-tech world continues to grow, so too does ATCO I-Tek. In a year marked by continued demand from industry and government for managed services and co-location facilities, ATCO I-Tek laid the groundwork to build a new world-class data centre in Alberta and expanded its suite of IT infrastructure clients. The company also achieved an elite level of certification, implemented several significant systems integration and enhancement projects, and rolled out new technologies to improve services and efficiencies for its clients.

Expanding Data Centre and Infrastructure Services

Recognizing the need for new data centre facilities and technology management services, ATCO I-Tek commenced planning to build a data centre in Alberta. This significant project will be a key element of ATCO I-Tek's continued growth and will contribute to the economic well-being and growth of Alberta's technology sector.

Leveraging its technology infrastructure expertise, ATCO I-Tek also expanded its base of external clients, including a contract with the City of Edmonton. The City of Edmonton required a secondary data centre solution to complement its computing environment, which in turn allows the City to run its businesses and deliver services to the citizens of Edmonton. ATCO I-Tek was awarded a three-year contract with the City with renewal options that could make the total term 10 years. Along with access to ATCO I-Tek's data centre facilities, the City will have access to ATCO I-Tek's technical expertise and support.

Data Security Certification

Fundamental to ATCO I-Tek's ability to provide services to customers is the requirement to demonstrate strong security, processes and controls when managing solutions on behalf of its customers.

In 2010, ATCO I-Tek achieved Payment Card Industry Data Security Standard (PCI DSS) certification, an elite level within the industry. The internationally recognized certification demonstrates the company's ongoing commitment to pro-actively protect customer credit card information.

PCI DSS specifies stringent and comprehensive requirements for security management, standards, policies, procedures, network architecture, software design and other critical protective measures. The certification validates that ATCO I-Tek's technical and operational data security solutions meet the strict standards established by the Payment Card Industry Security Standards Council, effectively safeguarding its clients from data breaches.

Other Operational Achievements

ATCO I-Tek implemented several significant systems integration and enhancement projects for its clients including an integrated solution to manage ATCO Electric's increasing volumes of meter data.

Applying leading application development methodologies, ATCO I-Tek also developed and integrated functionality for ATCO Electric that streamlines enrollment for energy retailers and simplifies bills for municipalities.

The company rolled out several new technologies including a virtual desktop and server environment that will provide efficiencies and improved service, and implemented numerous Voice over Internet Protocol (VoIP) solutions that will enhance the network and telephony functionality of ATCO I-Tek's customers.

The new 3,000 square foot ATCO Blue Flame Kitchen Learning Centre in Calgary.

ATCO Blue Flame Kitchen

ATCO Gas celebrated the opening of its first Blue Flame Kitchen Learning Centre in Calgary in October 2010, building on its 80-year history of providing Albertans "expert advice for everyday life."

ATCO Gas has taken an innovative approach to raising consumers' awareness of energy safety and efficiency by adding an important new dimension to a longstanding, trusted and valued Alberta service. ATCO Blue Flame Kitchen, the original home service department of ATCO Gas dating back to 1930, was developed originally to help homemakers get the best results when using the "exciting new cooking fuel—natural gas."

The new Learning Centre offers cooking classes that explore different cuisines and cooking techniques, as well as educational programs that address food safety, preparation, household dilemmas, energy safety and efficiency around the home. Classes are tailored to adults and families and specially designed school programs will also be offered.

Customers can also engage with many other ATCO Blue Flame Kitchen services, which include a toll-free advice line, website and cookbooks. Energy safety messages are incorporated across all the customer "touch points" and support all of the utility's safety campaigns, including "Call Before You Dig."

Together, these initiatives work to bring home messages of safety and efficiency for our customers.

Seasonal cookbooks are available for purchase at www.atcoblueflamekitchen.com.

Summer students Andrea Fleury (Métis - left) worked in Distribution Asset Management and Jenna Calahashen (Sucker Creek Cree Nation) supported the public consultation team for the Eastern Alberta DC Transmission Line.

Canadian Utilities' Aboriginal Commitment

Canadian Utilities (CU) works to build and maintain mutually beneficial relationships with Aboriginal communities and their people based on respect, trust and understanding of their interests. In 2010, CU continued to strengthen its relationships with Aboriginal communities across Canada. This was done through the signing of several memorandums of understanding (MOUs), partnering with the Government of Alberta to sponsor the Alberta's Future Leaders program, and ongoing community investment, support and recognition.

CU values the opportunity to establish positive working relationships with Aboriginal communities throughout Canada.

ATCO Group, and Northland Utilities sponsored the 40th Dene National Assembly. The Dene National Assembly represents all native people in regions of Denendeh of the NWT, including the Akaitcho Territory Government, Deh Cho First Nations, Gwich'in Tribal Council, Sahtu Dene Council and Tlicho. ATCO has had a long-term working relationship with the Dene people.

Wherever possible, CU seeks to support Aboriginal organizations and initiatives that contribute to sustainable economic and social development of Aboriginal communities. CU believes that supporting sustainable communities means also investing in young leaders through promoting education and providing work opportunities.

In partnership with the Government of Alberta, ATCO Electric provided financial and in-kind support to the Alberta's Future Leaders program for the Aboriginal communities of Peerless Lake and Trout Lake. Program components include sporting activities such as rock climbing, hiking, canoeing, and performing and visual arts. The program also includes leadership initiatives to build interpersonal development skills such as teamwork, self-esteem and conflict resolution. ATCO Electric's support to the program helps local youth develop leadership skills and self-confidence so that they can be positive role models and help improve the quality of life in their communities.

ATCO Electric continued to support training and work opportunities for Aboriginal youths through the company's Aboriginal Summer Student Program, and by participating in career fairs such as the National Aboriginal Achievement Foundation's Blueprint for the Future (BFF) career fair. BFF is a series of national career fairs designed to attract First Nation, Métis, and Inuit high school students to the wide array of potential careers available in all employment sectors.

Summer students Alana Runningrabbit (Siksika Nation - left) worked in Lands and Properties and Heather Mackinaw (Ermineskin Cree Nation) worked in Land and Records Management.

Since 2005, ATCO Group has sponsored the Arctic Youth Leadership program, a 14-day development and leadership training opportunity for Aboriginal youth.

ATCO Electric also collaborated with the Northern Alberta Institute of Technology to develop the ATCO Electric Aboriginal Pre-Technology Award.

On a local level, employees from ATCO Pipelines hand-delivered Food Bank donations to several First Nations with which ATCO Pipelines has relationships in the province of Alberta. In addition, CU employees participated in a number of events held by Aboriginal communities by volunteering their time and equipment that would otherwise be a cost to the communities.

CU is also pleased to recognize Major Robert (Bob) Crane (Retired), Senior Manager for Business Development with ATCO Structures & Logistics, which is 24.5 per cent owned by CU. On Remembrance Day, Mr. Crane was honoured at the 2010 Siksika Nation Armed Forces Pow-wow for achieving the highest rank of any Siksika First Nation veteran. In following the Siksika First Nation's traditional way of honouring warriors going into battle and celebrating their victorious return, Mr. Crane was granted a Siksika Warrior's head dress.

Summer student Amber Scoville (of Métis heritage) started as a student and now works full time as a Health, Safety & Environment Coordinator in Construction.

Financial Excellence 2010

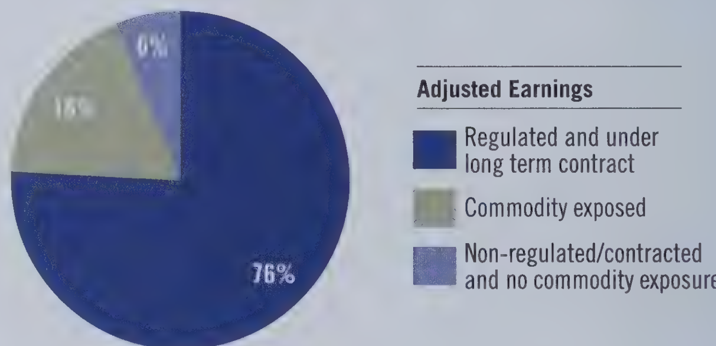
Brian R. Bale
Senior Vice President & Chief Financial Officer

Canadian Utilities has demonstrated reliability through its ability to generate strong earnings growth, even in challenging market conditions. In addition, the company has maintained financial strength through a strong balance sheet, which positions it well to realize on future growth opportunities. Canadian Utilities has also provided growth through a significant and well defined capital program in excess of $5 billion over the next three years. These three pillars of reliability, financial strength, and growth provide the foundation for delivering continuing value for share owners over both the near and long term.

Reliability with Opportunity for Premium Returns

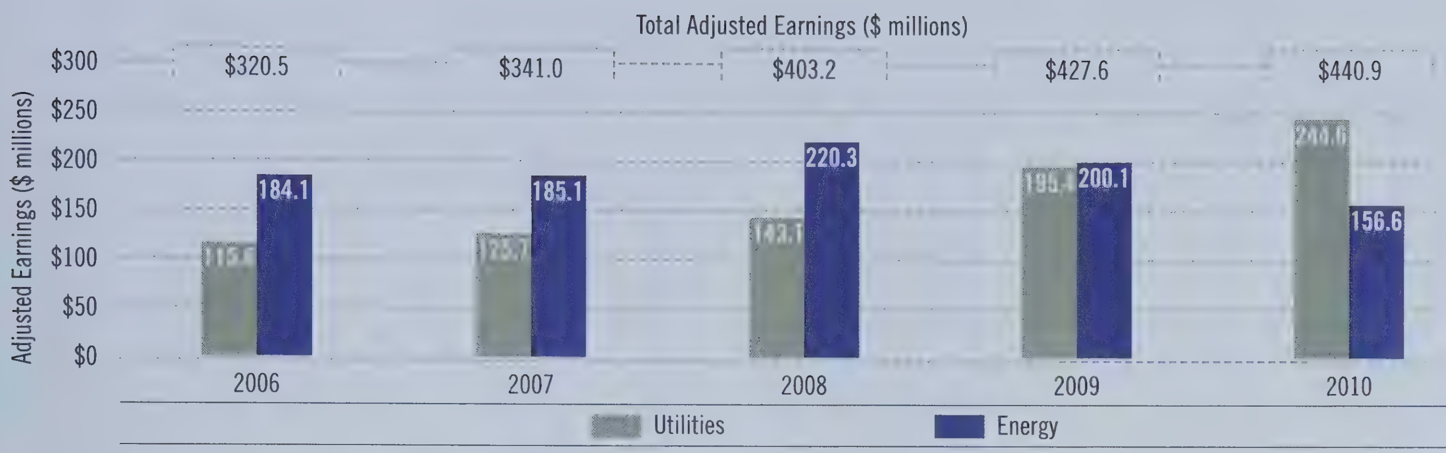
Canadian Utilities' diversified business platform has delivered notable returns and earnings growth over many years. This high degree of reliability has enabled Canadian Utilities to consistently increase dividends every year since 1972. The following chart illustrates the growth in adjusted earnings and dividends over the last five years. Adjusted earnings exclude one-time gains and items that are not in the normal course of business.

Over 76 per cent of adjusted earnings were generated from lower risk regulated utilities and operations that are supported by long term contracts. The remaining 24 per cent of adjusted earnings are generated from non-contracted power, energy services and other operations. Included in this 24 per cent is approximately 18 per cent that has direct exposure to commodity price fluctuations.



The benefits of diversification within Canadian Utilities have contributed to its reliable performance. The company's commodity based businesses are well positioned to benefit from improvements in commodity markets in the future. While commodity markets will in all likelihood continue to be volatile, Canadian Utilities has demonstrated that earnings growth can still be supported by the lower risk regulated utility and other long term contracted operations.

The effect of diversification can best be illustrated by highlighting the relative earnings contribution from Canadian Utilities' two primary business segments (excludes Corporate & Other). In a period where one business may be experiencing slower growth, the other business has grown more rapidly. The net impact has been multiple businesses working together to generate an overall increase in year over year earnings.



Canadian Utilities continues to focus on enhancing its geographic diversification. The company recently announced the launch of ATCO Australia which will take advantage of opportunities to further diversify its operations.

Financial Strength

Canadian Utilities has a strong balance sheet, which together with its diversified low risk business platform, is reflected in its 'A' credit ratings. At December 31, 2010, Canadian Utilities had $540 million of cash together with close to $1 billion of bank lines, providing a significant source of liquidity.

Canadian Utilities has grown its total assets by $2.4 billion over the past five years from $7.0 billion to $9.4 billion, an increase of 35 per cent. The company has not only maintained a strong balance sheet throughout this period of significant growth, but strengthened it with a Debt to Capitalization ratio of 45 per cent at the end of 2010 as compared to 51 per cent in 2006.

Canadian Utilities is committed to preserving its high investment grade ratings and will maintain an appropriate capital structure and an ample amount of liquidity through the major expansion program currently underway. Together with significant amounts of funds generated from operations that are available for reinvestment in the business, Canadian Utilities expects it will also look to issue significant amounts of long-term debt and preferred shares to finance its capital program through to 2014.

Growth

Over the next three years, Canadian Utilities has in excess of $5 billion of growth projects. Two of the largest projects are the estimated $1.6 billion 500 kV Eastern Alberta Direct Current (DC) Transmission Line that will run along a corridor on the east side of Alberta between Edmonton and Calgary, and the estimated $800 million Hanna Region Transmission Development in the southeast region of the province. The 500 kV DC line is considered part of the province's critical transmission infrastructure and was assigned to the company in 2009 by the Government of Alberta. The need for major transmission reinforcement in the Hanna area was approved by the Alberta Utilities Commission. Engineering and design work has commenced and final approvals for these projects are expected to be received by Q4 2011.

Expansion programs in our regulated companies will increase the size of the company by over 50 per cent, and will deliver significant long-term returns for share owners. For every $1 billion of capital invested in utility infrastructure, assuming 2010 approved regulatory returns and capital structure, the company will generate an average of $26 to $28 million of incremental annual earnings in the first five years after investment.

Reliability of earnings, a strong financial position, and a significant growth program are the three pillars that underpin Canadian Utilities' continuing commitment to delivering value for share owners today and into the future.

Consolidated Highlights

(Millions of Canadian dollars, except as indicated)	2010	2009	2008	2007	2006
INCOME STATEMENT					
Revenues	**2,657.2**	2,584.0	2,778.9	2,404.9	2,430.4
Earnings (1)					
Utilities	**244.6**	195.4	148.6	138.2	120.0
Energy	**150.7**	209.5	223.0	203.0	181.6
Corporate & Other and Eliminations	**39.7**	61.7	42.9	42.7	22.0
Earnings (1)	**435.0**	466.6	414.5	383.9	323.6
Adjusted earnings (2)	**440.9**	427.6	403.2	341.0	320.5
BALANCE SHEET					
Cash (3)	**539.6**	796.0	726.6	747.2	798.8
Total Assets	**9,415.3**	9,083.6	7,860.0	7,299.7	6,990.9
Capitalization (4)					
Long Term Debt	**3,060.3**	3,102.3	2,844.3	2,603.2	2,411.5
Non-recourse Long Term Debt	**302.8**	354.8	412.4	478.1	626.7
Equity Preferred Shares	**860.0**	785.0	625.0	625.0	636.5
Share Owners' Equity	**3,275.2**	3,046.1	2,748.5	2,517.1	2,322.9
Capitalization (4)	**7,498.3**	7,288.2	6,630.2	6,223.4	5,997.6
CASH FLOW STATEMENT					
Funds Generated by Operations (5)	**738.2**	793.4	796.5	688.6	641.0
Capital Expenditures					
Utilities	**788.9**	776.1	852.6	588.8	505.0
Energy	**67.1**	151.5	109.7	56.7	54.0
Corporate & Other	**13.0**	18.5	48.6	55.3	8.7
Capital Expenditures	**869.0**	946.1	1,010.9	700.8	567.7
RATIOS					
Return on equity (%)	**13.8**	16.1	15.7	15.9	14.2
Earnings per share ($)	**3.46**	3.71	3.30	3.06	2.57
Adjusted Earnings per share ($) (2)	**3.50**	3.40	3.21	2.72	2.54
Dividends paid per share ($)	**1.51**	1.41	1.33	1.25	1.40
Equity per share ($)	**26.01**	24.20	21.90	20.09	18.53
Class A non-voting closing share price ($)	**54.40**	43.75	40.50	46.40	47.73
Class B common closing share price ($)	**54.13**	43.77	40.00	46.00	47.66

(1) Earnings attributable to Class A and Class B shares.

(2) Adjusted Earnings are defined as earnings attributable to Class A and Class B shares after adjustments for items that are not in the normal course of business or a result of day to day operations. This measure is not defined by Generally Accepted Accounting Principles and may not be comparable to similar measures used by other companies. Descriptions of the adjustments are provided in the Significant Non-Operating Financial Items section of each year's Management's Discussion & Analysis that is available on SEDAR.

(3) Cash is defined as cash and short-term investments less bank indebtedness.

(4) This measure is not defined by Generally Accepted Accounting Principles and may not be comparable to similar measures used by other companies.

(5) Funds Generated by Operations is defined as cash generated from operations before changes in non-cash working capital. This measure is not defined by Generally Accepted Accounting Principles and may not be comparable to similar measures used by other companies.

Consolidated Five-Year Operating Summary

(Millions of Canadian dollars, except as indicated)	2010	2009	2008	2007	2006
UTILITIES					
Natural gas distribution operations					
Capital expenditures [1]	**194.5**	189.6	249.7	191.6	167.4
Pipelines (thousands of kilometres)	**38.0**	37.7	37.2	36.5	35.9
Maximum daily demand (terajoules)	**2,169**	2,184	2,130	1,819	1,861
Natural gas distributed (petajoules)	**237**	250	238	233	219
Average annual use per residential customer (gigajoules)	**120**	121	124	127	126
Customers at year-end (thousands)	**1,057.4**	1,037.4	1,022.2	1,001.8	969.9
Electric distribution and transmission operations					
Capital expenditures [1]	**511.5**	497.8	518.4	311.8	238.1
Power lines (thousands of kilometres)	**73.0**	72.1	71.5	70.9	70.1
Electricity distributed (millions of kilowatt hours)	**10,532**	10,431	10,594	10,744	10,286
Average annual use per residential customer (kWh)	**7,555**	7,671	7,666	7,690	7,495
Customers at year-end (thousands)	**237.2**	233.1	228.2	223.0	216.3
Natural gas transmission operations					
Capital expenditures [1]	**82.9**	87.7	81.7	87.1	97.7
Pipelines (thousands of kilometres)	**8.5**	8.4	8.4	8.4	8.4
Contract demand for pipelines system access (terajoules/day)	**4,757**	4,877	5,034	5,143	5,032
ENERGY					
Capital expenditures [1]	**67.1**	151.5	109.7	56.7	54.0
Generating capacity (megawatts)	**4,957**	4,885	4,885	4,840	4,840
Generating capacity owned (megawatts)	**2,582**	2,503	2,503	2,467	2,474
Availability (%)	**92.5**	94.9	93.5	91.6	93.0
Natural gas processed (Mmcf/day)	**401**	401	435	478	480
Natural gas gathering lines (kilometres)	**1,075**	1,000	1,000	1,000	1,000

(1) Includes purchases of property, plant and equipment and intangibles.

Participants at the opening ceremonies of the 2010 Arctic Winter Games in Grande Prairie, Alberta.

Making a Difference in our Communities

Canadian Utilities (CU) is committed to contributing to the quality of life in the communities where we do business and where our people work and live. Our investments include support to health and wellness, arts and culture, sports and recreation, youth and education, as well as projects and initiatives that strengthen the foundation of our communities. Working today to secure a healthy future is the philosophy behind the relationships CU has nurtured over many years of serving communities. In 2010, the CU companies undertook numerous initiatives ranging from contributing to local college scholarships and safe community programs to donations for fire halls and community centres.

2010 Highlights

ATCO EPIC

Through the company-wide ATCO Employees Participating In Communities (EPIC) program, CU and its people participated in the program which pledged to donate $2.97 million to more than 500 charities across Alberta in 2010. The program is a grassroots fundraising initiative involving employee-led committees that plan, implement and administer workplace fundraising campaigns within each CU company and the corporate office. Employees donate to the charity of their choice and CU matches their donations to human health and wellness charities, giving people the opportunity to make a difference in their own community. CU also absorbs all administration costs, ensuring that 100 per cent of the funds go directly to benefiting organizations.

The ATCO EPIC Time to Give program was created to recognize the contributions made by CU employees who volunteer their time and talents to charitable and non-profit organizations that are important in their lives. In 2010, ATCO and CU employees volunteered more than 34,000 hours to make our communities a better place to work and live.

ATCO Tyrrell Learning Centre

The Centre at the internationally renowned Royal Tyrrell Museum in Drumheller was officially opened in 2003 by the Government of Alberta and the ATCO Group of Companies, including CU. The funding to launch the ATCO Tyrrell Learning Centre is to enrich technically advanced educational programming opportunities.

The 16,500 square foot Centre includes three learning zones, a hands-on workshop, a distance learning studio and an innovative outdoor interpretive area. The Centre has expanded the museum's

ATCO Tyrrell Learning Centre at the Royal Tyrrell Museum in Drumheller, Alberta.

ATCO Gas volunteers sort food donations and pack hampers at the Calgary Inter-Faith Food Bank to help individuals and families in need.

education programs to meet the ever-increasing demand for information about Alberta's ancient history and famous dinosaur past, offering more video-conferencing programming than any other content supplier in Canada.

The Distance Learning Studio delivered more than 300 video-conferencing programs to almost 9,000 participants in 2010. In the past five years, audiences included more than 28,000 people across Canada and around the world, in 31 U.S. states and five countries including Mexico, Honduras and the Netherlands.

ATCO Gas Lost Kids Program

ATCO Gas has sponsored the Lost Kids program at the Calgary Stampede for the past 17 years, providing parents with extra support in protecting their kids. As parents enter the Stampede grounds, it has become a ritual to stop at the ATCO Gas Lost Kids Kiosk to ensure their children receive a wristband with a cell phone contact number written on it. If families become separated, the Lost Kids trailer provides an important meeting place.

The ATCO Gas Lost Kids stations distributed 42,000 wristbands to children and parents in 2010. CU employees volunteer to work at the kiosks in a Day of Caring on Kids' Day.

The ATCO Gas Lost Kids Patrol provides ID wristbands to kids as they enter the Calgary Stampede. The program helps reunite lost kids with their parents.

Toys donated by employees brought smiles and laughter to the children of Haiti.

Shelby Gitzel, a Grande Prairie student, ignites the 2010 Arctic Winter Games cauldron from the ATCO Electric hybrid truck bucket. ATCO Gas built the cauldron that was permanently installed in Grande Prairie.

Donations to Haitian families

ATCO and Canadian Utilities (CU) worked with a Haitian non-governmental organization (NGO), La Maison l'ARC-en-Ciel (Rainbow House), near Port-au-Prince, to distribute thousands of high-priority items, such as tools, medical and school supplies, toiletries, linens and toys to Haitian families following the earthquake in 2010.

The items were donated by ATCO and CU employees who sought to provide tangible help for a country that has experienced so much devastation. The response from employees across Canada was overwhelming, with more than 34,000 items donated in just a few weeks.

Rainbow House estimated that more than 600 people associated with their programs have benefited directly from the donations. The NGO has been recognized by UNICEF for its work with Haitian children and families.

Canadian Blood Services

ATCO Gas was recognized by Canadian Blood Services for its longstanding support of Canada's vital blood donor program. ATCO Gas was the first company to join the Alberta branch of Canadian Blood Services' Partners for Life program in 2008. ATCO Gas employees annually pledge to donate at least 1,200 units of blood through the program and have either met or exceeded this goal since joining.

Arctic Winter Games

Canadian Utilities (CU) has been involved in the North since 1901, through Yukon Electrical and Northland Utilities Enterprises. In 2010, CU companies sponsored the 21st bi-annual Arctic Winter Games, held in Grande Prairie, Alberta.

Nearly 2,000 athletes and cultural participants from Arctic nations around the world competed and showcased their talents. CU provided people, products and services to the Games including the supply of temporary modular units used in the athletes' village and at the sport venues, support of the volunteer lounges, construction of the Games cauldron and volunteers.

CU has a long history of supporting Northern athletes, artists and performers as they participate in these events. CU employees who live and work in the North appreciate the opportunity to assist Northern youth in their quest for excellence.


ATCO
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Electric

Canadian Utilities Limited

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Charles W. Wilson
Corporate Director

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Assistant Corporate Secretary

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Roberta L. (Bobbi) Lambright
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ATCO Electric

Steven J. Landry
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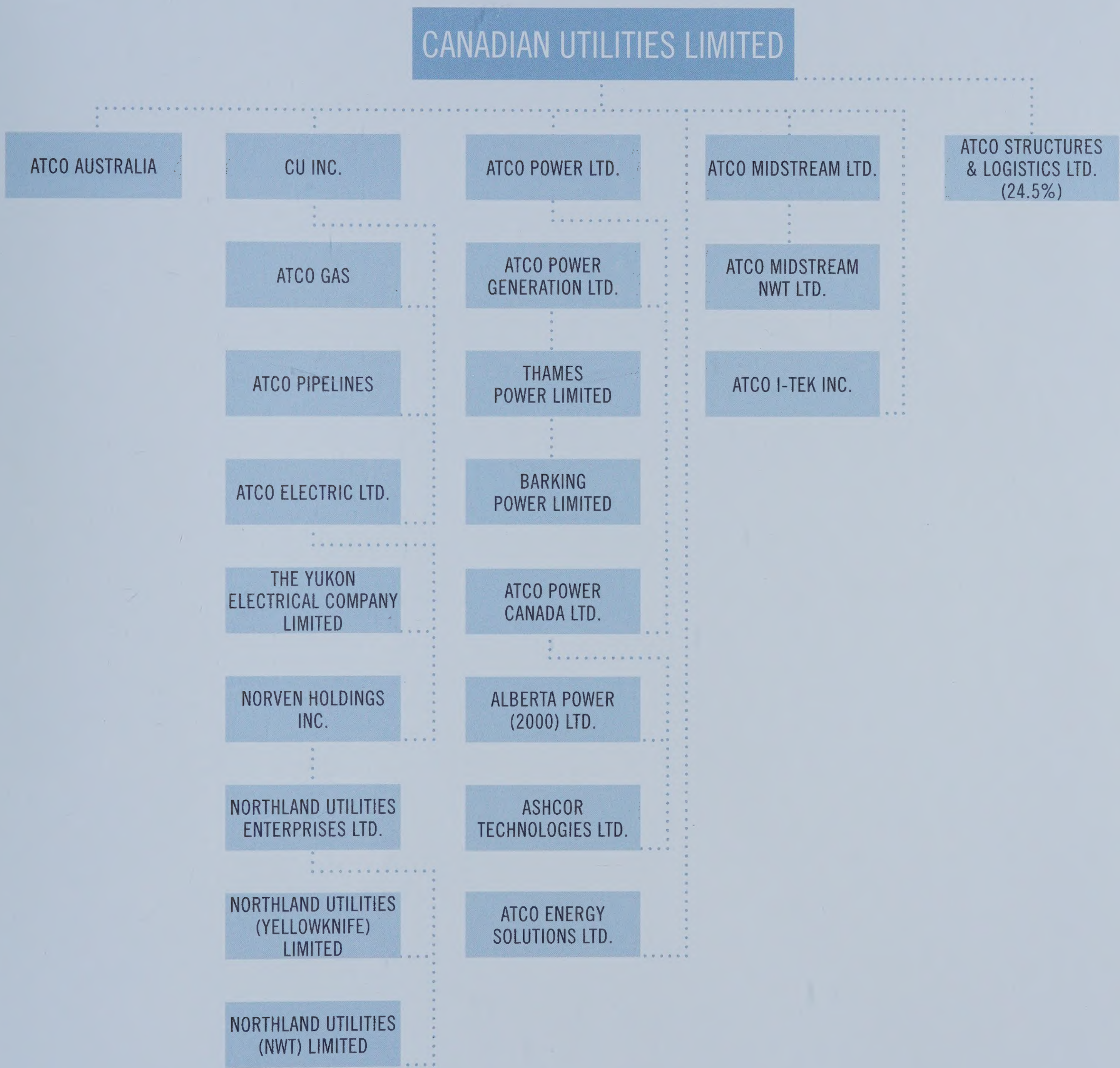
Brendan G. Dolan
Senior Vice President
& General Manager,
ATCO Pipelines

Grant M. Lake
Senior Vice President,
Development Division,
ATCO Electric

Canadian Utilities Limited Operational Structure



The Environment

Canadian Utilities is committed to making significant strides in environmental innovation. ATCO Group's Sustainability Report consolidates key data and information from its eight diverse principal operating subsidiaries. The report covers the previous two years' performance in the areas of community, safety, employees and environment.

The report will be available at www.canadian-utilities.com or www.atco.com

General Information

Incorporation

Canadian Utilities Limited was incorporated under the laws of Canada on May 18, 1927 and was continued under the Canada Business Corporations Act by Articles of Continuance on August 15, 1979.

Annual Meeting

The Annual Meeting of Share Owners will be held at 10:00 a.m. on Thursday, May 5, 2011 at The Fairmont Hotel Macdonald, 10065-100 Street, Edmonton, Alberta.

Auditors

PricewaterhouseCoopers LLP
Calgary, Alberta

Counsel

Bennett Jones LLP
Calgary, Alberta

Transfer Agent and Registrar

Class A non-voting and
Class B common shares and
Second Preferred (Series W and X) Shares
CIBC Mellon Trust Company
Calgary/Montreal/Toronto/Vancouver

Trustee, Transfer Agent and Registrar Debentures

BNY Trust Company of Canada
Calgary/Toronto

Stock Exchange Listings

Class A non-voting Symbol CU
Class B common Symbol CU.X
Listing: The Toronto Stock Exchange
Cumulative Redeemable Second Preferred Shares
5.80% Series W Symbol CU.PR.A
6.00% Series X Symbol CU.PR.B
Listing: The Toronto Stock Exchange

ATCO Group Annual Reports

Annual Reports to Share Owners and Financial Information (Consolidated Financial Statements & Management's Discussion and Analysis) for ATCO Ltd. and Canadian Utilities Limited are available upon request from:

ATCO Ltd. & Canadian Utilities Limited
Corporate Secretary
1400, 909 – 11th Avenue SW
Calgary, Alberta T2R 1N6
Telephone: (403) 292-7500
Website: www.atco.com
www.canadian-utilities.com

Share Owner Inquiries

Dividend information and other inquiries concerning shares should be directed to:

CIBC Mellon Trust Company
P.O. Box 7010
Adelaide Street Postal Station
Toronto, Ontario M5C 2W9

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Fax: (416) 643-5501

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